FILED
1-14-16
04:59 PM

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
FINAL 2015 RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

[Redactions in Appendices A, B, C, D, F (in its entirety) and H]

CHARLES R. MIDDLEKAUFF
M. GRADY MATHAI-JACKSON

Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-6971
Facsimile: (415) 973-5520
Email: CRMd@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: January 14, 2016

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) FINAL 2015 RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

Pursuant to Ordering Paragraph ("OP") 2 in Decision ("D.") 15-12-025, Pacific Gas and Electric Company ("PG&E") respectfully submits its final 2015 Renewable Portfolio Standard Procurement Plan ("2015 RPS Plan"), which has been modified consistent with D.15-12-025. This filing includes both clean and redlined versions of the public and confidential versions of PG&E's 2015 RPS Plan, with the redline showing changes from the draft 2015 RPS Plan filed on August 4, 2015. The redlines show all changes made subsequent to, and in compliance with, the Commission's approval of the draft 2015 RPS Plan on December 17, 2015. A clean version of the public 2015 RPS Plan is included as Attachment A and a redline version is included as Attachment B. A clean version of the confidential 2015 RPS Plan is included as Attachment C to the confidential version of this filing and a redline version is included as Attachment D to the confidential version of this filing.

PG&E is also providing the following table, which describes the substantive changes made in the 2015 RPS Plan as well as the basis for the change. The table below does not include the correction of grammar, typos, or minor updates in the 2015 RPS Plan. PG&E included minor updates to some portions of the 2015 RPS Plan to reflect legislative or regulatory events which occurred after the 2015 RPS Plan was filed on August 4, 2015.

Final 2015 RPS Plan Reference	General Description of Change	Authority for Change in D.15-12-025
Introduction	Changed to reflect approval of PG&E's 2015 RPS Plan	OP 1
Section 1.2	Added language that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2015 RPS Plan, except for RPS amounts that are separately mandated.	OP 9
Section 2.2	Statutory requirement for the Commission to report on the procurement expenditure limit ("PEL") by January 1, 2016 was deleted in Senate Bill ("SB") 350 from California Public Utilities Code Section 399.15, so the date reference was deleted from Section 2.2.	Update
Section 2.3	Added reference to Commission decision approving SB 1122 contracts and tariffs.	Update
Section 2.4	Added section regarding the passage of SB 350.	Update and reflecting discussion on pp. 5-6 of D.15-12-025
Section 3.3.1	Added language that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2015 RPS Plan, except for RPS amounts that are separately mandated.	OP 9
Section 7	Included language indicating that the Commission was not specifically approving a bank size proposal and instead would be addressing the appropriate bank size in the implementation of SB 350.	P. 92
Section 9	Added language that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2015 RPS Plan, except for RPS amounts that are separately mandated.	OP 9
Section 9	Added language in response to Ordering Paragraph 7 regarding ensuring there is no double counting between the Integration Cost Adder and Net Market	OP 7

Final 2015 RPS Plan Reference	General Description of Change	Authority for Change in D.15-12-025
	Value components in the Least-Cost Best-Fit methodology.	
Section 9.1	Updating Time of Delivery (“TOD”) factors.	OP 7

Respectfully submitted,

CHARLES R. MIDDLEKAUFF
M. GRADY MATHAI-JACKSON

By: */s/ Charles R. Middlekauff*
CHARLES R. MIDDLEKAUFF

Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-6971
Facsimile: (415) 973-5520
E-mail: CRMd@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: January 14, 2016

VERIFICATION

I, Brendan Lucker, am an employee of Pacific Gas and Electric Company, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing *Pacific Gas and Electric Company's (U 39 E) Final 2015 Renewable Energy Procurement Plan (Public Version).*

The statements in the foregoing document are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 8th day of January, 2016 at San Francisco, California.

/s/ Brendan Lucker
BRENDAN LUCKER
Manager, Renewable Energy Strategy
Pacific Gas and Electric Company

ATTACHMENT A

Clean version of the Public 2015 RPS Plan

Public

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

FINAL 2015 RENEWABLE ENERGY PROCUREMENT PLAN

JANUARY 14, 2016

Public

TABLE OF CONTENTS

TABLE OF CONTENTS

(CONTINUED)

TABLE OF CONTENTS

(CONTINUED)

LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its Final 2015 Renewables Portfolio Standard ("RPS") Plan ("2015 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the Commission in Decision ("D.") 15-12-025. PG&E's 2015 RPS Plan includes a summary of key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the *Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewable Portfolio Standard Procurement Plans* ("ACR") issued in this proceeding on May 28, 2015.[1]

1 Summary of Key Issues

1.1 PG&E's RPS Position

PG&E projects that under both the current 33% RPS by 2020 target, as well as a 40% by 2024 scenario, it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods and will not have incremental procurement need until at least 2022. Under the current 33% RPS target, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying banked volumes of excess procurement ("Bank") beginning in [redacted]. Under the 40% RPS by 2024 scenario, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying Bank beginning in [redacted]. In both situations, PG&E anticipates additional steady, incremental long-term procurement in subsequent years to avoid the need to procure large volumes in any single year to meet compliance needs and maintain minimum Bank levels.

1.2 PG&E Will Not Hold a Request for Offers in 2015

Given its current RPS compliance position, PG&E will not hold an RPS solicitation in 2015. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for

---

1 *See* ACR, pp. 8-20.

future solicitations in next year's RPS Plan. Although many factors could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs in 2016.[2] PG&E will seek permission from the Commission to procure any amounts other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff ("FIT") and RAM) during the time period covered by the 2015 solicitation cycle. In 2016, PG&E will reassess its Renewable Net Short ("RNS") position and determine its updated procurement needs. PG&E's decision to not hold a 2015 RPS solicitation is consistent with a proposal made by San Diego Gas & Electric Company ("SDG&E") in its 2014 RPS Plan, and approved by the Commission given SDG&E's lack of need.[3]

1.3 Consideration of Higher RPS Targets Should Be Integrated With Broader State Greenhouse Gas Goals

California's RPS has played, and will continue to play, an important role in lowering electric sector greenhouse gas ("GHG") emissions and meeting the state's clean energy goals. PG&E supports maintaining the existing requirements that load-serving entities ("LSE") provide a minimum of 33% RPS in 2020, moving towards 50% in 2030. However, PG&E believes California's clean energy policy should be centered on achieving the most cost-effective GHG reductions needed to meet the Governor's 2030 goal of emissions that are 40% below 1990 levels.[4]

---

2 Mandated programs include Renewable Auction Mechanism ("RAM"), Renewable Market Adjusting Tariff ("ReMAT"), and Bioenergy Market Adjusting Tariff ("BioMAT"). In addition, while not pursuant to the RPS mandate, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

3 D.14-11-032, p. 32, Ordering Paragraph 17.

4 Office of California Governor Edmund G. Brown, Executive Order 4-29-2015 (available at http://gov.ca.gov/news.php?id=18938).

Before taking any action that would increase the RPS requirements, the Commission should consider how the RPS program fits within a comprehensive GHG policy framework built to achieve emissions reductions through a combination of actions, as opposed to potentially inefficient carve-out mechanisms.[5] Renewable energy policy should be more completely aligned with this broader policy context in order to ensure that GHG reduction targets are achieved in an integrated and economically efficient manner. Rather than reflexively raise the RPS targets, the CPUC should adopt a strategy focused on flexibility, equitable rules for all LSEs, affordability, and market and system stability.[6]

1.4 Renewable Portfolio Growth Increases Customer Rate Impacts

As a part of this RPS Plan, PG&E is providing historic and forecasted RPS cost and rate information. From 2003-2015, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. The costs of the RPS Program have already and will continue to impact customer bills. From 2003-2016, PG&E estimates its annual rate impact from RPS procurement has increased from 0.7 cents per kilowatt-hour ("¢/kWh") in 2003 to an estimated 3.5¢/kWh in 2016.[7] The growth in rates due to RPS procurement costs will continue to increase through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh, or approximately $2.3 billion. Further detail regarding RPS costs is provided in Section 13 and the annual rate impact of forecasted procurement is detailed in Table 2 of Appendix D.

---

5 For further discussion of the cost impacts of mandated procurement programs, see Section 13.3.

6 For further discussion, see PG&E's opening and reply comments in response to *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program (R.15-02-020)* filed on March 26, 2015 and April 6, 2015, respectively.

7 "Annual Rate Impact" should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

To address these rate impacts, PG&E's procurement strategy attempts to minimize cost and maximize value to customers, while satisfying the RPS program requirements. To accomplish this goal, PG&E promotes competitive processes to procure incremental RPS volumes, strategically uses its Bank, and avoids long-term over-procurement.

As described above, a more integrated GHG policy framework that enables LSEs to adapt to changing needs, costs, and circumstances and manage the integration of variable resources would provide additional opportunities to lower customer costs. New technologies will emerge and the mix and cost-effectiveness of GHG emissions reduction strategies will undoubtedly evolve over the next several years. PG&E believes that a more flexible implementation of the RPS Program that allows LSEs to optimize a portfolio of different GHG reduction strategies would facilitate meeting the State's environmental goals at the lowest possible costs and best portfolio fit, and provide the maximum benefits to customers. Similarly, as discussed in Section 13.3, mandated procurement programs within the RPS reduce the program's efficiency while increasing costs.

1.5 PG&E's Bank Is Necessary to Ensure Long-Term Compliance

PG&E views its Bank as necessary to: (1) mitigate risks associated with variability in load; (2) protect against project failure or delay exceeding forecasts; and (3) avoid intentional over-procurement above the 33% RPS target by managing year-to-year generation variability from performing RPS resources. The Bank allows PG&E to mitigate the need to procure additional RPS products at potentially high market prices in order to meet near-term compliance deadlines. With an adequate Bank, PG&E aims to minimize customer cost by having the flexibility not to procure in "seller's market" situations. More information on forecasted Bank size and minimum Bank levels under both 33% and 40% RPS is provided in Section 7 below.

PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's RNS, future RPS cost projections, and assessment of the current Renewable Energy Credit ("REC") market do not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

1.6 RPS Rules Should Be Applied Consistently and Equitably Across All LSEs

PG&E's long-term position is a forecast based on a number of assumptions, including a certain amount of load departure due to Community Choice Aggregation ("CCA") and distributed generation growth. While it is possible that this forecasted load departure may not fully materialize or occur at the rate assumed in the forecast, PG&E's forecast is a reasonable scenario based on current trends. Under the existing percentage-based RPS targets, any departure of PG&E's load to CCAs naturally results in both a reduction of PG&E's required RPS procurement quantities and a corresponding increase in RPS procurement by CCAs. Thus, CCAs will be required to shoulder an increasing portion of the State's RPS procurement goals. The consistent and equitable application of all RPS rules and requirements to all Commission-jurisdictional LSEs, including CCAs and Energy Service Providers ("ESPs"), will help to ensure that all LSEs are helping California achieve its ambitious renewable energy goals.

2 Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E's portfolio forecast and procurement decisions are influenced by ongoing legislative and regulatory changes to the RPS Program. The following is a description of recent changes to the RPS Program that have impacted PG&E's RPS procurement.

2.1 Commission Implementation of Senate Bill 2 (1x)

Senate Bill ("SB") 2 (1x), enacted in April 2011 and effective as of December 11, 2011, made significant changes to the RPS Program, most notably extending the RPS goal from 20% of retail sales of all California investor-owned utilities ("IOUs"), ESPs, publicly owned utilities, and CCAs by the end of 2010, to a goal of 33% of retail sales by

2020. The Commission issued an Order Instituting Rulemaking to implement SB 2 (1x) in May 2011 and has subsequently issued a number of key decisions implementing certain "high priority" issues needed to implement the complex provisions of SB 2 (1x). In February 2015, the Commission opened a new Rulemaking (R.) 15-02-020 to address remaining issues from this earlier proceeding, as well as other elements of the ongoing administration of the RPS Program. Commission action on remaining and new key issues may impact PG&E's procurement need and actions going forward, notwithstanding the forecasts and projections included in this Plan.

Key Commission decisions issued to date implementing SB 2 (1x) include D.11-12-052 which defined portfolio content categories ("PCC"), D.11-12-020 which outlined compliance period targets for the 33% RPS target, and D.12-06-038 which implemented changes to the RPS compliance rules for retail sellers, including treatment of prior procurement to meet RPS obligations for both the 20% and 33% RPS Programs. D.12-06-038 also adopted rules on calculating the RPS Bank, meeting the portfolio balance requirements, and for reporting annually to the Commission on RPS procurement. Finally, on December 4, 2014, the CPUC adopted D.14-12-023 setting RPS compliance and enforcement rules under SB 2 (1X).

2.2 Cost Containment

When California's legislature passed SB 2 (1x), it required the CPUC to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS target from causing "disproportionate rate impacts." If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only "de minimis" rate impacts.

PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E strongly supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. PG&E urges the Commission to finalize the PEL as soon as possible.

2.3 Implementation of Bioenergy Legislation

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ("MW") in total of new small-scale bioenergy projects 3 MW or less through the FIT Program. The total IOU program MWs are allocated into three technology categories: 110 MW for biogas from wastewater plants and green waste; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. The allocation of MWs by project type for each IOU, as well as the program design, is being determined by the Commission in proceedings currently underway. PG&E has worked with the Commission and stakeholders in order to ensure that the SB 1122 program is implemented in a way that balances the needs of the bioenergy industry with clear cost containment mechanisms that protect customers from excessive costs. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 program ("BioMAT") began accepting participants on December 1, 2015 and the first program period will start on February 1, 2016.

2.4 Senate Bill 350

On October 7, 2015, Governor Brown signed SB 350 (de Leon), known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increases the RPS target from 33% in 2020 to 50% in 2030. The Commission will begin implementation of SB 350 in 2016.

3 Assessment of RPS Portfolio Supplies and Demand

3.1 Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's 33% RPS target. PG&E is currently required to procure the following quantities of RPS-eligible products:

- 2011-2013 (First Compliance Period): 20% of the combined bundled retail sales.
- 2014-2016 (Second Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
- 2021 and beyond: 33% of combined retail sales in 2021.[8]

Based on preliminary results presented in Appendix C.2a, PG&E delivered 27.0% of its power from RPS-eligible renewable sources in 2014.

As described more fully in Section 7 and reported in the current RNS calculations in Appendix C.2a, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. Under the 33% RPS target, PG&E projects that it will not have incremental procurement need until at least 2022, with need beginning in [redacted], after applying Bank beginning in [redacted].

8 SB 350 establishes the following new multi-year RPS compliance period: 40% by the end of 2021-2024; 45% by the end of 2025-2027; and 50% by the end of 2028-2030 and each year thereafter.

Under a 40% RPS scenario, PG&E modeled the same trajectory through 2020 as described above, but modeled the following RPS requirements starting in 2021:

- 33% of combined bundled retail sales in 2021;
- 37% of combined bundled retail sales in 2022;
- 37% of combined bundled retail sales in 2023; and
- 40% of combined bundled retail sales in 2024 and each year thereafter.

For this scenario, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E projects that it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. PG&E projects that it will have incremental procurement need beginning in [redacted], after applying its Bank towards its physical net short beginning in [redacted].[9]

3.2 Supply

3.2.1 Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes over 8,000 MW of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar photovoltaic ("PV"), biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 6 and 7.

As described in further detail in Section 7.1, for the 2015 RPS Plan, PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of approximately 99% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's

---

9 This projection includes future volumes from mandated programs, such as the RAM and FIT Programs.

2012 RPS Plan, to 100% in PG&E’s 2013 RPS Plan, and 87% in PG&E’s 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E’s portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations. While PG&E has continued to see a general trend towards higher project success rates, the change in its success rate assumption from 2014 to 2015 (from 87% to 99%) reflects the recent removal of several projects from PG&E’s portfolio due to contract terminations and an update to the “Closely Watched” category described in Section 6.

Consistent with the project trends reported in its 2014 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit (“ITC”) and Production Tax Credit (“PTC”)) have continued to increase many projects’ cost-effectiveness, contributing to their eventual completion. Progress in the siting and permitting of projects has also supported PG&E’s sustained high success rate. As described in more detail in Section 3, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in Sections 5 and 6.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 6, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted,[10] although these resources are encouraged to bid into PG&E's future competitive solicitations.

3.2.2 Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission adopted D.15-01-051 implementing a GTSR framework, approving the IOUs' applications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.

Pursuant to D.15-01-051, PG&E has submitted several advice letters related to implementation of the GTSR program that are currently pending before the Commission. In February, PG&E filed an advice letter containing its plans for advance procurement for the GTSR Program and identifying the eligible census tracts for environmental justice projects in its service territories.[11] In May, together with Southern California Edison Company and SDG&E, PG&E submitted a Joint Procurement Implementation Advice Letter, addressing each utility's plans for ongoing GTSR Program procurement and RPS resource and REC separation and tracking.[12] Concurrently, PG&E filed a Marketing Implementation Advice Letter[13] and a Customer-Side Implementation Advice Letter[14] with details regarding implementation. In addition, to accommodate GTSR procurement, PG&E filed Advice Letter 4605-E to

---

10 Although the physical net short calculations in PG&E's deterministic model do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive. PG&E's deterministic and stochastic models are described in more detail below in Section 6.

11 PG&E Advice Letter 4593-E (supplemented March 25, 2015).

12 Advice Letter 4637-E.

13 Advice Letter 4638-E.

14 Advice Letter 4639-E.

change its RAM 6 Power Purchase Agreements ("PPA") and Request for Offer ("RFO") instructions, consistent with the minimum goals for 2015 identified in D.15-01-051.[15]

The GTSR program will impact PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected; and (2) PG&E's retail sales will be reduced corresponding to program participation. The GTSR decision permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. PG&E will implement tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff programs. Because the GTSR implementation Advice Letters discussed above[16] have not yet been approved, PG&E's RNS calculation submitted with this RPS Plan does not reflect the impact of GTSR on PG&E's RPS position. Due to the relatively small volumes of the GTSR interim pool compared to PG&E's overall RNS position, PG&E believes that its forecasts of meeting the second and third compliance period RPS targets as well as its incremental need year under either a 33% or 40% RPS would remain the same once these small GTSR volumes are incorporated. PG&E will update future RNS calculations to reflect GTSR program impacts after the advice letters implementing the program are approved.

3.2.3 RPS Market Trends and Lessons Learned

As PG&E's renewable portfolio has expanded to meet the RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the three key goals of: (1) reaching, and sustaining, the 33% RPS target; (2) minimizing

---

15 *See* D.15-01-051, Section 4.2.4, pp. 25-28.

16 Advice Letters 4637-E, 4638-E and 4639-E.

customer cost within an acceptable level of risk; and (3) ensuring it maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty. However, PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as solar PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend driven by growth of renewable resources in the California Independent System Operator ("CAISO") system is the downward movement of mid-day market prices. Many renewable energy project types have little to no variable costs and therefore additions tend to move market clearing prices down the dispatch stack. This has led to a change in the energy values associated with RPS offers, with decreasing value of renewable projects that generate during mid-day hours.

The growth of renewable resources has also produced operational challenges, such as overgeneration situations and negative market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address overgeneration and negative pricing situations that are likely to increase in frequency in the future. These provisions have both operational and customer benefits. From an operational perspective, this flexibility allows PG&E to offer its RPS-eligible resources into the CAISO's economic dispatch, which can reduce the potential for overgeneration conditions and facilitate reliable operation of the electrical grid. In addition, economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 11.

3.3 Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Compliance rules for the RPS Program were established in D.12-06-038. In addition, the Commission issued D.11-12-052, to define three statutory PCCs of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 6; in particular, uncertainty around bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

3.3.1 Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need through [redacted] under a 33% RPS requirement and through [redacted] under a 40% RPS scenario, PG&E plans not to hold an RPS solicitation in 2015. As discussed in the summary of key issues, PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future RFOs in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts in 2016 through mandated procurement programs, such as the RAM, ReMAT, and BioMAT Programs. PG&E will seek permission from the Commission to procure any amounts other than amounts separately mandated by the Commission (*i.e.*, FIT and RAM) during the time period covered by the 2015 solicitation cycle.

3.3.2 Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. PG&E's most recent Load Forecast, which is used in this RPS Plan, is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan ("BPP") submitted in October 2014 in R.13-12-010. PG&E updates the bundled load forecasts annually to reflect any new events and to capture actual load changes. It is important to emphasize that PG&E's Alternative Scenario is a forecast that includes a number of assumptions regarding events which may or may not occur.

PG&E is currently projecting a decrease in retail sales in 2015 and a continued retail sales decrease through 2024, followed by modest growth thereafter. These changes are driven by the increasing impacts of Energy Efficiency, customer-sited generation, and Direct Access ("DA") and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 6, 7, and 8, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for its risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 6 and 7.

3.4 Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs such as the RAM, ReMAT, and BioMAT Programs, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting in the 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value ("NMV") methodology will be updated to use the values and methodologies of the final integration cost adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[17]

3.5 RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the NMV valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity have the potential to reduce integration challenges. PG&E's use of

---

17 *See* PG&E, 2014 RPS Solicitation Protocol, pp. 24-28 (available at http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf).

the integration cost adder in its NMV valuation process may also result in procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement. PG&E's current quantitative and qualitative approach to resource diversity would remain the same under a 40% RPS scenario as the existing approach described above.

3.6 Optimizing Cost, Value, and Risk for the Ratepayer

From 2003 to 2012, PG&E's annual RPS-eligible procurement and generation costs from its existing contracts and utility-owned portfolio grew at a relatively modest pace. However, the costs of the RPS program are becoming more apparent on customer bills and will increase as RPS projects come online in significant quantities. Over the period of two years (2013 and 2014), the renewable generation in PG&E's portfolio increased by approximately the same amount that it grew over the entire prior history of the RPS Program (2003-2012). In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible, particularly when entering into incremental long-term commitments. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement; and (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to help limit long-term over-procurement. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13.3, as PG&E makes progress toward achieving the 33% RPS target, it expects that the cost impacts of mandated procurement programs that focus on particular technologies or project size may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process, in which all technologies can compete to offer the best value to customers at the lowest cost.

3.7 Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2020 and to minimize customer cost within an acceptable level of risk. PG&E's optimization strategy continues to evolve as its RPS compliance position through 2020 and beyond continues to improve. Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (post-2020). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to manage a 33% RPS operating portfolio after 2020. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 6 and 7.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement; (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E will not hold a 2015 RPS solicitation, future incremental procurement to avoid the need to procure extremely large volumes in any single year remains a central component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes consideration of sales of surplus procurement that provide a value to customers.

The third component of the optimization strategy is effective use of the Bank. Under the existing 33% RPS target and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in [redacted]. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted].

Under a 40% RPS by 2024 scenario, the components of PG&E's optimization strategy would remain the same. However, under the 40% RPS scenario and current market assumptions, PG&E would plan to maintain a minimum Bank size of at least [redacted]. See Section 7 for additional information regarding the use and size of PG&E's Bank.

4 Project Development Status Update

In Appendix B, PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of June 17, 2015.[18] These key project development status indicators help PG&E to determine if a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions.

Within PG&E's active portfolio,[19] there are 107 RPS-eligible projects that were executed after 2002. Seventy-six of these contracts have achieved full commercial operation and started the delivery term under their PPAs. Thirty-one contracts have not started the delivery term under their PPAs. Of the 31 contracts that have not started the delivery term under their PPAs with PG&E: 18 have not yet started construction; five have started construction but are not yet online; and eight are delivering energy, but have not yet started the delivery term under their PPAs. Based on historic experience, projects that have commenced construction are generally more viable than projects in the pre-construction phase, although PG&E expects most of the pre-construction projects currently in its portfolio to achieve commercial operation under their PPA.

5 Potential Compliance Delays

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E is familiar with the obstacles confronting renewable energy developers. These include securing financing, siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these

---

18 Appendix B includes PPAs procured through the RAM and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has 72 executed Assembly Bill 1969 PPAs in its portfolio and 29 ReMAT PPAs, totaling 104 MW of capacity. These small renewable FIT projects are in various stages of development, with 60 already delivering to PG&E under an AB 1969 PPA and 11 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

19 PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and CPUC-approved as of June 17, 2015, not including amended post-2002 QF contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation ("UOG") projects, or FIT projects.

issues. However, even with these efforts, challenges remain that could ultimately impact PG&E's ability to meet California's RPS goals. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. This section describes the most significant RPS compliance risks and some of the steps PG&E is taking to mitigate them.[20]

5.1 Project Financing

The financing environment for solar PV and wind projects continues to be healthy, with access to low-cost capital and a variety of ownership structures for project developers. However, for renewable technologies that are less proven, less viable, or reflect a higher risk profile, the financing environment is more constrained, with higher costs of capital and fewer participants willing to lend or invest.

Federal and state incentives such as the PTC and ITC continue to fuel renewable growth in California. In 2015, the Internal Revenue Service extended the applicable dates for the "beginning of construction" guidance for PTC-eligible facilities to January 1, 2015, and the "placed in service" date to January 1, 2017.[21] This allows the PTC or ITC tax benefits for non-solar facilities to continue well beyond 2014. Solar energy facilities continue to be eligible for a 30% ITC if they are placed in service by December 31, 2016.[22] The five-year and seven-year Modified Accelerated Cost

---

20 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

21 Notice 2015-2025 allows a taxpayer to claim a PTC under Section 45 of the Internal Revenue Code ("IRC"), or a 30% ITC under Section 48 (ITC) in lieu of the PTC, for eligible facilities such as wind, geothermal, biomass, marine, landfill gas, and hydro, if the facility began construction before January 1, 2015 or was placed in service by January 1, 2017.

22 Section 48 of the IRC allows for a tax credit equal to 30% of project's qualifying costs for certain types of commercial energy projects, including solar, geothermal, fuel cells, and small wind projects, and a 10% tax credit for geothermal, micro turbines and combined heat and power. The tax credit is realized in the year that the project is placed in service.

Recovery System ("MACRS") allows for accelerated tax depreciation deductions to renewable tangible property.[23] These tax incentives and the MACRS depreciation deductions enable businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for projects to negotiate financing. As a result, tax incentives have spurred significant investment in renewable energy and generally amount to between 35 and 60 cents per dollar ("¢/$") of capital cost.

Tax equity remains a core financing tool for renewable developments, and ownership structures such as Master Limited Partnerships and Yield Cos are also being utilized as project sponsors market and investors competitively shop for solar and wind investments. These structures allow developers who cannot use tax benefits efficiently to barter the benefits to large corporations or investors in exchange for cash infusions for their projects. At this time, tax incentive structures after 2016 are unknown. The PTC and 30% ITC incentives end in 2016. Unless the tax code is modified or extended, the renewable energy ITC will drop to 10% after December 31, 2016. However, there are efforts underway to extend or modify the PTC and ITC.[24] Despite the uncertainty surrounding renewable energy project tax incentives, PG&E believes there are indications that healthy trends for renewable project financing will continue.

---

23 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.

24 H.R. 2412 would extend the renewable energy ITC for a period of five years for eligible renewable solar, small wind energy, fuel cell, micro turbine, thermal energy and combined heat and power system properties that begin construction before January 1, 2022.

In addition, in its proposed budget for fiscal year 2016, the Obama administration proposes to modify and permanently extend the renewable PTC and ITC. For facilities that begin construction in 2016 or later, the proposal would make the PTC permanent and refundable. Solar facilities that qualify for the ITC would be eligible to claim the PTC. The proposal would also permanently extend the ITC at the 30 percent credit level, which is currently scheduled to expire for properties placed in service after December 31, 2016, and it would make permanent the election to claim the ITC in lieu of the PTC for qualified facilities eligible for the PTC.

5.2 Siting and Permitting

PG&E works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development. For example, PG&E works collaboratively with environmental groups, renewable energy developers and other stakeholders to encourage sound policies through a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the timely development of energy resources in the California desert and other suitable locations. Long-term and comprehensive planning and permitting processes can help better inform and facilitate renewable development.

PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of offers to PG&E's future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects while ensuring environmental integrity.

Permitting challenges for projects are improving as a result of these and other efforts to streamline and adjust the permitting process for renewable energy projects. While these improvement efforts are ongoing, permitting and siting hurdles remain for renewables projects. Common issues may include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected species, and county-imposed moratoriums. These hurdles may impact development schedules for projects.

5.3 Transmission and Interconnection

Achieving timely interconnection is an important part of the project development process. Delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.

Over the past few years, the CAISO and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how these projects would be connecting into the California grid has become increasingly challenging. The growth in these requests has, in turn, extended estimated project development timelines, which creates a significant barrier to financing projects endeavoring to come online within tight contractual milestone dates. Similarly, the growth in interconnection requests has made it difficult to estimate reliable interconnection study results and to identify necessary transmission build-outs.

Accordingly, PG&E has initiated a number of internal efforts and collaborated on external initiatives to address these challenges at both the transmission and distribution levels. Recent notable changes in the distribution-level interconnection process included: (1) amending the Wholesale Distribution Tariff in October 2014 to address modifications similar to those made to the CAISO's Tariff; and (2) amending Rule 21 in January 2015 to capture the technological advances offered by smart inverters.

Additionally, over the past few years, PG&E has worked with the CAISO and industry stakeholders in ongoing stakeholder initiatives enhancing the transmission-level interconnection processes. Most significant among the changes has been the Generator Interconnection and Deliverability Allocation Procedures, which has streamlined the process for identifying customer-funded transmission additions and upgrades under a single comprehensive process. This initiative also provides incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations. PG&E has also actively contributed to the CAISO's Interconnection Process Enhancements stakeholder initiative that seeks to continuously review potential enhancements to the generator interconnection procedures.

Finally, at the intersection of transmission-level and distribution-level interconnections, is the Distributed Generation Deliverability ("DGD") process. In 2013, PG&E collaborated extensively with the CAISO to implement the first annual cycle, and the second and third cycles were successfully completed in 2014 and 2015, respectively. Under the DGD Program, the CAISO conducts an annual study to identify MW amounts of available deliverability at transmission nodes on the CAISO-controlled grid. Based on the deliverability assessment results, distributed generation facilities that are located or seeking interconnection at nodes with identified available deliverability may apply to the appropriate Participating Transmission Owner (“PTO”) to receive an assignment of deliverability for Resource Adequacy (“RA”) counting purposes.

5.4 Curtailment of RPS Generating Resources

As discussed in more detail in Section 11, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may present an RPS compliance challenge. In order to better address this challenge, PG&E’s stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 6.2.

5.5 Risk-Adjusted Analysis

PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. As described further in Section 6, deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E’s net short calculation.

PG&E’s experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. As described in Section 8, PG&E’s current expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E’s existing portfolio, which are captured in PG&E’s deterministic model. These deterministic results are time-sensitive and do not account for all of the risks and uncertainties that can cause substantial swings in PG&E’s portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 33% RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

6 Risk Assessment

Dynamic risks, such as the factors discussed in Section 5 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales variability and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[25] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at

---

25 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as Voluntary Margin of Procurement or VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 6.1 identifies the three risks accounted for in PG&E's deterministic model. Section 6.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 6.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 6.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 7 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices C.2a and C.2b. Section 8 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

6.1 Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

1) **Standard Generation Variability:** the assumed level of deliveries for categories of online RPS projects.
2) **Project Failure:** the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.
3) **Project Delay:** the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
DETERMINISTIC MODEL RISKS

RISK	METHODOLOGY	APPLIES TO
Standard Generation Variability	• For non-QF projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled “OFF” (0% deliveries assumption) • All other In Development projects are “ON” (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment/Communication with counterparties	Under Construction Projects/ Under Development Projects/ Approved Mandated Programs

6.1.1 Standard Generation Variability

With respect to its operating projects, PG&E’s forecast is divided into three categories: non-Qualifying Facilities (“QF”); non-hydro QFs; and hydro projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, calendar year deliveries, and regularly updated with PG&E’s latest internal hydro updates. The UOG and Irrigation District and Water Agency (“IDWA”) forecast is based on PG&E’s latest internal hydro updates. Future years’ hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix G.

6.1.2 Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0% deliveries) and ON (represented with 100% deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":

    - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.).
    - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data).
    - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization.
    - Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability.
    - Whether a PPA amendment has been executed but has not yet received regulatory approval.
    - Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[26]

2. **ON** – Projects in all other categories are assumed to deliver 100% of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON" projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of "ON" projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of "ON" projects represents executed and future contracts from CPUC-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes with replacement projects within a reasonable timeline.

6.1.3 Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

---

26 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

6.2 Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E's RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E's portfolio. PG&E's stochastic model assesses the impact of both demand- and-supply-side variables on PG&E's RPS position from the following four categories:

1) **Retail Sales Variability:** This demand-side variable is one of the largest drivers of PG&E's RPS position.
2) **Project Failure Variability:** Considers additional project failure potential beyond the "on-off" approach in the deterministic model.
3) **Curtailment:** Considers buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment.
4) **RPS Generation Variability:** Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year-to-year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
CATEGORIZATION OF IMPACTS ON RPS POSITION

Higher Impact on RPS Position

Lower Impact on RPS Position

Impact	Categorization
1. **Retail Sales Variability**: Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** (*If an outcome occurs, the effect persists through more than one year).*
2. **RPS Generation Variability:** Variability in yearly generation is largely an annual phenomenon that has little persistence across time.	**Variable and short-term** (*If an outcome occurs, the effect may only occur for the individual year.)*
3. **Curtailment:** Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
4. **Project Failure Variability:** Lost volume from project failure persists through more than one year.	**Variable and persistent**

6.2.1 Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, electric vehicles, and distributed generation. However, the variability in load loss due to DA and CCA is not modeled in this same way. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting substantial increases in DA. Load loss due to CCA departure is modeled as an expected value based on an increased forecast of CCA departure. Because forecast errors tend to carry forward into future years, the cumulative impact of load forecast variability grows with time. Appendix F.1 lists the resulting simulated retail sales and summary statistics for the period 2015-2030.

Appendices F.5a and F.5b show the resulting simulated RPS target when accounting for the retail sales variability for the period 2015-2030 in the 33% and 40% RPS, respectively.

6.2.2 RPS Generation Variability

Based on analysis of historical hydro generation data from [redacted], wind generation data from [redacted], and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is essentially uncorrelated among technologies. Appendices F.3a and F.3b list the resulting simulated generation and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, Appendices F.4a and F.4b, combine the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, shows how these variables interact in the 33% and 40% RPS, respectively.

6.2.3 Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). [redacted]

[redacted][27] These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information regarding curtailment.

6.2.4 Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

---

27 [redacted]

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Projects that are re-contracted, in contrast, are modeled at a [redacted] success rate. Appendices F.2a and F.2b list PG&E's simulated failure rate and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

6.2.5 Comparison of Model Assumptions

Table 6-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 7 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 6-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years	Distribution based on most recent (2015) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate.
3) RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment[28]	None	33% RPS Target: [redacted] of RPS requirement 40% RPS Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond.

6.3 How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position and procurement need. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well

28 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance.

as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

6.4 How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives, (b) inputs, and (c) constraints of the model.

    a. The objective is to minimize procurement cost.

    b. The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes[29]) in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] GWh, which is in addition to volumes available for re-contracting.[30]

    c. The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

---

29 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can also re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive.

30 PG&E limited modeling to a maximum addition of [redacted] GWh per year in order to avoid modeling outcomes that required "lumpy" procurement patterns. Large swings in annual procurement targets could lead to boom/bust development cycles and could expose PG&E's customers to additional price volatility risk.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.
3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.
4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not currently consider speculating on price volatility through sales of PG&E's Bank in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2015 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

6.5 Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the 33% and 40% RPS are shown in Row La of PG&E's Alternate RNS in Appendices C.2a and C.2b.

The stochastic model does not provide guidance on potential sales of excess banked procurement at this time. However, as PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted] above the [redacted] threshold.

The results of both the deterministic and stochastic models are discussed further in Section 7 and minimum margin of procurement is addressed in Section 8.

7 Quantitative Information

As discussed in Section 6, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix C. Appendices C.1a and C.1b presents the RNS in the form required by the *Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendices C.2a and C.2b are a modified version of Appendices C.1a and C.1b to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its bank size and PG&E's analysis of the minimum bank needed. However, in approving the 2015 RPS Plan, the Commission expressly rejected any specific bank size proposal and instead indicated that proposals regarding bank size should be considered in SB 350's implementation.

7.1 Deterministic Model Results

Results from the deterministic model under the 33% RPS target are shown as the physical net short in Row Ga of Appendices C.1a and C.2a, while the results from the deterministic model under the 40% RPS scenario are shown as the physical net short in Row Ga of Appendices C.1b and C.2b. Appendices C.1a and C.1b provide a physical net short calculation using PG&E's Bundled Retail Sales Forecast for years 2015-2019 and the LTPP sales forecast for 2020-2035, while Appendices C.2a and C.2b rely exclusively on PG&E's internal Bundled Retail Sales Forecast. Following the methodology described in Section 6.1, PG&E currently estimates a long-term volumetric success rate of approximately 99% for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendices C.2a and C.2b. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendices C.2a and C.2b depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

7.1.1 33% RPS Target Results

Under the current 33% RPS target, PG&E is well-positioned to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.1b, the deterministic model shows a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2a also shows a physical net short of approximately 500 GWh beginning in 2022.

7.1.2 40% RPS Scenario Results

Under a 40% RPS scenario, PG&E is forecasted to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of

Appendix C.2b, PG&E has a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2b shows a physical net short of approximately 3,000 GWh beginning in 2022.

7.2 Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for both the current 33% RPS target and a 40% RPS scenario. All assumptions and caveats stated in the discussion of the 33% RPS target results apply to the 40% RPS scenario results, unless otherwise stated. However, note that the 40% RPS scenario results apply to this particular RPS scenario only, and PG&E's optimization strategy may differ under other scenarios that have a different RPS target or timeline. Because PG&E uses its stochastic model to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix C.2a for the current 33% RPS target and Appendix C.2b for the 40% RPS scenario. Appendices C.1a and C.1b provide an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendices C.2a and C.2b, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

7.2.1 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 33% RPS Target

To evaluate possible procurement strategies, PG&E selected a cumulative ([redacted]) non-compliance risk target of [redacted], which PG&E views as the maximum reasonable level of non-compliance risk. Figure 7-1 shows the model's forecasted procurement need and resulting Bank usage under the current 33% RPS.

Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2a provides the detailed results. Annual forecasted Bank usage is shown in Row Ia of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by 2030. The [redacted] SONS is [redacted] than the physical net short in Row Ga for [redacted], as the SONS [redacted].

[redacted]

[redacted]

[redacted]

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

7.2.2 Bank Size Forecasts and Results – 33% RPS Target

Figure 7-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2030. PG&E's total Bank size as of the end of compliance period is approximately 900 GWh, shown as existing Bank in Figure 7-2. The stochastic model's results currently project PG&E's Bank size to [redacted] GWh by [redacted] (as shown in Figure 7-2, as well as in Appendix C.2a, Row J). [redacted]

[redacted]

[redacted]

[redacted]

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases.

7.2.3 Minimum Bank Size – 33% RPS Target

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 7-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]. This time period was selected as it best represents a "steady state" period when the Bank approaches a minimum level and moderate incremental procurement is required to maintain compliance. Note that given the uncertainty around the inputs in the stochastic model, without a Bank to accommodate such uncertainty, the amount of RPS generation is almost as likely to miss the RPS target as exceed it. One standard deviation over [redacted] is approximately [redacted] GWh, as indicated on Figure 7-3. That is, given this particular procurement scenario, about 68% of the simulations have a difference that is up to plus or minus approximately [redacted] GWh.

However, this does not suggest that a Bank of [redacted] GWh would be adequate to cover potential shortfalls over this [redacted]-year period. It would result in an unacceptable non-compliance risk over [redacted] of approximately [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level. Based on current model assumptions and inputs, Figure 7-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

[redacted]

[redacted]

As stated in Section 7.2.2, the stochastic model's results show PG&E's forecasted [redacted] PG&E's strategy is to procure steady, incremental volumes in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs and maintain minimum Bank levels. [redacted]

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 7-3 illustrates.

7.2.4 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 40% RPS Scenario

Figure 7-4 shows the model's forecasted procurement need and recommended Bank usage in the 40% RPS scenario. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2b provides the detailed results. Annual forecasted Bank usage can be seen in Row Ia of this Appendix. The first year of procurement need is currently forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by [redacted]. The [redacted] SONS is [redacted] than the physical net short shown in Row Ga for [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

7.2.5 Bank Size Forecasts and Results – 40% RPS Scenario

Figure 7-5 shows PG&E's current and forecasted cumulative Bank from Compliance Period 1 through 2030 under a 40% RPS scenario. PG&E's total Bank size as of the end of Compliance Period 1 is approximately 900, shown as existing Bank in Figure 7-5. The stochastic model's results currently project PG&E's [redacted] (as shown in Figure 7-5, as well as in Appendix C.2b, Row J).

[redacted]

[redacted]

[redacted]

7.2.6 Minimum Bank Size – 40% RPS Scenario

Using a similar approach as described in Section 7.2.3, under a 40% by 2024 scenario, a minimum Bank size of at least [redacted] GWh is necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The minimum Bank size in this scenario is greater than the Bank required for the 33% RPS target, as more volumes are required to meet the higher RPS, but also [redacted].

[redacted]

[redacted]

The stochastic model's procurement strategy results show PG&E's forecasted [redacted]. Based on current model assumptions and inputs, Figure 5-6 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

7.3 Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales of surplus procurement. Consistent with the Commission's adopted RNS methodology, PG&E's physical net short and cost projections do not include any projected sales of bankable contracted deliveries.

However, PG&E will consider selling non-bankable surplus volumes in its portfolio and, in doing so, may identify and propose in the future opportunities to secure value for its customers through the sale of bankable surplus procurement. PG&E will update its physical RNS if it executes any such sale agreements and will include in its optimized RNS and SONS specific future plans to sell RPS procurement.

8 Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 33% RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

8.1 Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[31] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors

[31] Cal. Pub. Util. Code § 399.13(a)(4)(D).

the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[32]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[33] However, as discussed in Sections 6 and 7, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

8.2 Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin of procurement.[34] As discussed further in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

---

32 *Id.*, § 399.15(b)(5)(B)(iii).

33 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums. However, its revised success rate assumption (from 87% to 99%) also reflects several recent contract terminations from PG&E's portfolio due to and an update to the "Closely Watched" category described in Section 6.

34 *Id.*,§ 399.13(a)(4)(D).

While PG&E's current optimization strategy projects [redacted]. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% RPS target, and will thus reduce long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 6 and 7.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

9 Bid Selection Protocol

As described in Sections 3 and 7, PG&E is well positioned to meet its RPS targets, under both a 33% RPS target and a 40% RPS scenario, until at least [redacted]. As a result, PG&E will not issue a 2015 RPS solicitation. PG&E will continue to procure RPS-eligible resources in 2016 through other Commission-mandated programs, such as the ReMAT and RAM Programs. To reflect that PG&E will not issue a 2015 RPS Solicitation, language has been added throughout the final 2015 RPS Plan to confirm that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2015 RPS Plan, except for RPS amounts that are separately mandated.

In D.15-12-025, the Commission required in Ordering Paragraph 7 that PG&E "include a description of how their process ensures that there is no double counting between the Integration Cost adder and the Net Market Value components in the Least-Cost Best-Fit methodology of [its] RPS plan[]. . .." If PG&E were to procure RPS resources, there would be no double counting between the integration cost adder and the Net Market Value ("NMV") components in the Least-Cost Best-Fit ("LCBF") methodology that would be used by PG&E. NMV measures the cost of the renewable resource in terms of direct impacts on ratepayers—PPA payments to the supplier plus transmission costs and integration costs, less the energy and capacity value of the resource. It is associated with the marginal value of the energy and capacity produced directly by the resource—it is the market cost that PG&E no longer incurs because it is procuring energy and capacity from the resource instead. The integration cost represents the system costs that are incurred for *other* resources that are needed to support the additional renewable resource. The variable cost represents the incremental cost of running existing flexible units in the short term, and the fixed cost represents the incremental cost of additional flexible RA capacity to support the additional renewable resource.

9.1 Proposed Time of Delivery Factors

PG&E sets its Time of Delivery ("TOD") factors based on expected hourly prices. Given the high penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be significant periods of time during the mid-day when net loads are low, resulting in prices that will be low or negative, especially in the spring. This expectation is consistent with forecasts of net load that have been publicized by the CAISO.[35] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. Thus, PG&E would simplify its PPAs and include only a single set of TOD factors to be applied to both energy-only and fully deliverable resources.

---

35 *See*, *e.g.*, *CAISO Transmission Plan 2014-2015*, pp. 162-163 (approved March 27, 2015) (available at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).

PG&E is updating its TOD factors and TOD periods as follows:

<u>New TODs</u>

- Move peak period from HE16-HE21 to HE17-HE22
- Move mid-day period from HE07-HE15 to HE10-HE16
- Move night period from HE22-HE06 to HE23-HE09
- Move March back to the "Spring" period
- Result: Summer=Jul.-Sep., Winter=Oct.-Feb., Spring=Mar.-Jun.; and Peak=HE17-HE22, Mid-day=HE10-HE16, Night=HE23-HE09

TABLE 9-1
RPS TIME OF DELIVERY FACTORS

	Peak	Mid-Day	Night
Summer	1.479	0.604	1.087
Winter	1.399	0.718	1.122
Spring	1.270	0.280	1.040

10 Consideration of Price Adjustment Mechanisms

The ACR requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index ("CPI"), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[36]

PG&E will consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the

36 ACR, p. 15.

legislature has found is a benefit of the RPS Program.[37] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[38]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

11 Economic Curtailment

In D.14-11-042, the Commission approved curtailment terms and conditions for PG&E's pro forma RPS PPA.[39] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the

---

37 *See* Cal. Pub. Util. Code § 399.11(b)(5).

38 *See* D.11-04-030, pp. 33-34.

39 D.14-11-042, pp. 43-44.

Procurement Review Group ("PRG").[40] In May 2015, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally, and PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in 2015 has generally increased in the Real-Time Markets, even during the low hydro conditions of 2015. During January through May 2015, negative price intervals in the CAISO Five Minute Market for the North of Path 15 Hub occurred more than 1,800 times (4.2% of 5 minute intervals) compared to 1,100 times (2.5%) during the same period in 2014. Similarly, the ZP26 Hub prices for this period in 2015 were negative over 4,100 times (9.5%), a substantial increase over the 2014 results of 1,400 times (3.3%). Increased negative price periods have led to increased curtailments of renewable resources that are economically bid. The specific occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted].

[redacted]

---

40 *Id.*, pp. 42-43.

[redacted] [41] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. This also includes the incremental costs of compliance instruments required to comply with the 33% RPS target. PG&E provided more detail concerning its RPS bidding strategy in its proposed 2014 BPP which was filed with the Commission in October 2014 and is currently pending at the Commission.[42]

[redacted] [43] [redacted][44] While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods and also potentially enhancing CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events.

---

41 [redacted]

42 *See* PG&E, *Proposed 2014 Bundled Procurement Plan*, R.13-12-010, Appendix K (Bidding and Scheduling Protocol) (October 3, 2014).

43 [redacted]

44 [redacted]

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. Under the 33% RPS target, PG&E assumes curtailment [redacted][45] under a 40% RPS scenario, PG&E expects curtailment to increase in line with recent CAISO estimates [redacted].[46] These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

12 Expiring Contracts

The ACR requires PG&E to provide information on contracts expected to expire in the next 10 years.[47] Appendix E lists the projects under contract to PG&E that are expected to expire in the next 10 years. The table includes the following data:

1. PG&E Log Number
2. Project Name

---

45 [redacted]

46 [redacted]

47 ACR, p. 16.

3. Facility Name
4. Contract Expiration Year
5. Contract Capacity (MW)
6. Expected Annual Generation (GWh)
7. Contract Type
8. Resource Type
9. City
10. State
11. Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA

As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects that proposed material amendments (i.e., those needed to avoid project failure) or extensions to existing contracts will be evaluated against current offers.

13 Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix D provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix D outlines the methodology for calculating the costs and generation.

13.1 RPS Cost Impacts

Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-2014) and forecast (2015-2030). From 2003 to 2014, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than [redacted] in procurement costs for RPS-eligible resources in 2014.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS-eligible procurement and generation. While this formula does not provide an estimate of the renewable "above-market premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix D illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 3.5¢/kWh in 2016, meaning the average rate impact from RPS-eligible procurement has increased more than five-fold in approximately 12 years. This growth rate is projected to continue increasing through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

13.2 Procurement Expenditure Limit

Section 399.15(f) provides that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding "a de minimis increase in rates." The methodology for the PEL, the Commission's cost containment mechanism, is still under development. As discussed in Section 2.2, PG&E looks forward to the Commission finalizing the PEL methodology and implementing it, to ensure that customers are adequately protected and promote regulatory certainty and support procurement planning.

13.3 Cost Impacts Due to Mandated Programs

As PG&E makes progress toward achieving the RPS goal of 33%, the cost impacts of mandated procurement programs that focus on particular technologies or project size increase over time, and procurement from those programs increasingly comprises a larger share of PG&E's incremental procurement goals. In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[48] Studies have also shown that renewable electricity mandates increase prices and costs,[49] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants and second, by creating a less robust market for participants to compete.[50] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the

---

48 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et. al, "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

49 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call" (available at http://www.instituteforenergyresearch.org/pdf/statereport.pdf); Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

50 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

14 Imperial Valley

For the IOUs' 2014 RPS solicitations, the Commission did not specifically require any remedial measures to bolster procurement from Imperial Valley projects but required continued monitoring of IOUs' renewable procurement activities in the Imperial Valley area.[51] Even without remedial measures in PG&E's 2014 RPS Solicitation, the Independent Evaluator monitoring that solicitation found that:

> Overall, the response of developers to propose Imperial Valley projects was robust and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to developers active in the Imperial Valley or that there was any structural impediment in the RFO process that hindered the selection of competitively priced Offers for projects in the Imperial Valley.[52]

Given the robustness of the response from Imperial Valley projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, and given the fact that PG&E is not planning on conducting a 2015 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the Imperial Valley as a part of the RPS Plan.

The ACR also directs the IOUs to report on any CPUC-approved RPS PPA for projects in the Imperial Valley that are under development, and any RPS projects in the Imperial Valley that have recently achieved commercial operation.[53] PG&E has one PPA under contract in the Imperial Valley. That project is in development.

---

51 D.14-11-042, pp. 15-16.

52 PG&E, *Advice Letter 4632-E*, p. 40, Section 2 (IE Report) (May 7, 2015).

53 ACR, p. 19.

Commercial operation is expected in 2016, with deliveries under the PPA beginning in 2020.

15 Important Changes to Plans Noted

This section describes the most significant changes between PG&E's 2014 RPS Plan and its 2015 RPS Plan. A complete redline of the draft 2015 RPS Plan against PG&E's 2014 RPS Plan was included as Appendix A of the August 4, 2015 draft RPS Plan. This section identifies and summarizes the key changes and differences between the 2014 RPS Plan and the proposed 2015 RPS Plan. Specifically, the table below provides a list of key differences between the two RPS Plans:

Reference	Area of Change	Summary of Change	Justification
Section 1	Section format and structure	Remove "Executive Summary" from Introduction.	Ease of document flow.
Entire RPS Plan	Consideration of a Higher RPS Requirement	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Section 2.1	Commission Implementation of SB 2 (1x)	Include discussion of D.14-12-023, setting RPS compliance and enforcement rules under SB 2 (1X).	ACR at p. 4.
Section 3.2.2	Impact of Green Tariff Shared Renewable Program	Include discussion of impact of Green Tariff Shared Renewable Program on RPS position.	D.14-11-042; D.15-01-051.
Section 3.4	Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations	Include discussion of integration cost adder as part of LCBF bid evaluation methodology.	ACR at p.15.
Section 3.5	RPS Portfolio Diversity	Include discussion of efforts to increase portfolio diversity.	ACR at p.10.

Reference	Area of Change	Summary of Change	Justification
Section 5.4	Curtailment of RPS Generating Resources	Include discussion of economic curtailment as a potential compliance delay.	ACR at p.16.
Section 11	Economic Curtailment	Include discussion of economic curtailment.	ACR at p.16.
Appendix C.1b	Renewable Net Short Calculations – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix C.2b	Alternate Renewable Net Short Calculations – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.2b	Project Failure Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.3b	RPS Generation Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.4b	RPS Deliveries Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.5b	RPS Target Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.

16 Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

16.1 Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2015 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[54] PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, PG&E's Safety Commitment, Personal Safety Commitment and Keys to Life.[55] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental

---

54 *See* PG&E, "Employee Code of Conduct" (August 2013) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 3 (available at http://www.pgecorp.com/aboutus/ethics_compliance/con_con_ven/).

55 *See* PG&E, "Employee Code of Conduct" *supra* (describing the Safety Principles, Safety Commitment, Personal Safety Commitment and Keys to Life).

authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its General Rate Case ("GRC"),[56] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance.

---

56 *See* PG&E, *Prepared Testimony, 2014 GRC, Application 12-11-009*, Exhibit (PG&E-6), Energy Supply, pp. 1-11, 2-17, 2-44, 2-66, 4-13 (available at http://www.pge.com/regulation/).

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident ("MVI") Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800 phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and re certification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E is developing and implementing a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

PG&E will never be satisfied in its safety performance until there is never an injury to any of its employees, contractors, or members of the public. Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement change that can improve safety performance.

16.2 Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. While this authority has not changed, PG&E intends to add additional contract provisions to its contract forms to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

Specifically, the safety language that PG&E is developing builds upon the former standard of Good Utility Practices to a new standard of Prudent Utility Practices, which includes greater detail on the types of activities covered by this standard, including but not limited to safeguards, equipment, personnel training, and control systems.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information. Additionally, the new contract provisions would require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. If the generator has repeated safety violations or challenges, the generator could be at greater risk of failing to meet a key project development milestone or failing to meet a material obligation set forth in the PPA.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

17 Energy Storage

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014. In D.14-10-045, the CPUC approved PG&E's application with modifications. PG&E filed final storage RFO results for CPUC approval on December 1, 2015. In addition, PG&E is participating in a new proceeding, R.15-03-011, which the Commission opened in March 2015 to consider policy and implementation refinements to the energy storage procurement framework and program design.

PG&E considers eligible energy storage systems to help meet its Energy Storage Program targets through its RPS procurement process, Energy Storage RFO, as well as other CPUC programs and channels such as the Self-Generation Incentive Program. PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[57]

---

[57] *See* PG&E, *Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Resources (2014-2015 Biennial Cycle)*, (available at: http://www.cpuc.ca.gov/NR/rdonlyres/D9CACD21-AB1C-411A-8B79-84FB28E88C58/0/PGE_StorageApplication.pdf).

APPENDIX B

Project Development Status Update

January 14, 2016

Appendix B - Project Development Status Update

Line No.	IOU ID	Project Name	Primary Developer	Technology Type	Contract Capacity (MW)	Expected Energy (GWh)	Energy Delivery Status	Vintage	CPUC Approval Status	Financing Status	Permit Status	Guaranteed Construction Start Date	Expected or Actual Construction Start Date	Construction Status	Status of Interconnection Agreement	Guaranteed COD	Expected or Actual COD
1	33R255	Kansas	Dominion Solar Holdings, Inc.	Solar Photovoltaic	20	47	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	12/31/2016	12/26/2014
2	33R279	Alamo Solar, LLC	Dominion Solar Holdings, Inc.	Solar Photovoltaic	20	50	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	Complete	Complete	5/20/2015	5/20/2015
3	33R291	Shafter Solar	NextEra Energy Resources	Solar Photovoltaic	20	53	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	Complete	Complete	10/10/2015	6/3/2015
4	33R148	North Star Solar 1	Southern Renewable Partnerships, LLC	Solar Photovoltaic	60	136	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	6/20/2015	[redacted]
5	33R278	Columbia Solar Energy, LLC	Hanergy Holding America, Inc.	Solar Photovoltaic	19	41	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	5/20/2015	[redacted]
6	33R324	Woodmere Solar Farm	sPower	Solar Photovoltaic	15	33	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	2/3/2016	[redacted]
7	33R322	Rising Tree Wind Farm II LLC	EDP Renewables North America LLC	Wind	20	69	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	Complete	Complete	2/3/2016	[redacted]
8	33R254	SPI Biomass Portfolio	Sierra Pacific Industries	Biomass	58	346	[redacted]	Existing / New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	9/23/2015	[redacted]
9	33R292	Morelos Del Sol	Gestamp Asetym Solar North America	Solar Photovoltaic	15	33	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	12/10/2015	[redacted]
10	33R287	Sand Hill Wind, LLC	Ogin, Inc.	Wind	20	44	[redacted]	Repowered	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	[redacted]	12/10/2015	[redacted]
11	33R326	Blackwell Solar Park, LLC	Frontier Renewables LLC	Solar Photovoltaic	20	48	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	2/3/2016	[redacted]
12	33R367	Altech III	Ogin, Inc.	Wind	20	53	[redacted]	Repowered	CPUC Approved	[redacted]	[redacted]	N/A	N/A (Existing)	[redacted]	[redacted]	11/1/2016	[redacted]
13	33R375	Westside Solar, LLC	Nextera Energy Resources, LLC and its subsidiary Aries Solar Holding, LLC	Solar Photovoltaic	20	55	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	5/30/2017	[redacted]
14	33R329	Diablo Winds (2)	NextEra Energy Resources, LLC	Wind	18	62	[redacted]	Existing	CPUC Approved	[redacted]	Complete	N/A	N/A (Existing)	Complete	Complete	7/1/2016	[redacted]
15	33R361	Maricopa West Solar PV 2, LLC	E.ON Climate and Renewables North America, LLC	Solar Photovoltaic	20	55	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	[redacted]	1/17/2017	[redacted]
16	33R257	Cuyama Solar Array	First Solar, Inc.	Solar Photovoltaic	40	104	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Complete	12/31/2019	[redacted]
17	33R259	Henrietta Solar	SunPower	Solar Photovoltaic	100	244	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	10/1/2016	[redacted]
18	33R362	Portal Ridge Solar C Project	First Solar, Inc.	Solar Photovoltaic	11	30	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	1/17/2017	[redacted]
19	33R374	CED Corcoran Solar 3, LLC	Con Edison Development	Solar Photovoltaic	20	49	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	5/30/2017	[redacted]
20	33R364	Sunray 20	Cogentrix Solar Holdings, LLC	Solar Photovoltaic	20	51	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	[redacted]	1/17/2017	[redacted]
21	33R133	Potrero Hills Landfill	DTE Biomass Energy	Biogas Generation	8	56	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	12/6/2016	[redacted]
22	33R376	Aspiration Solar G LLC	FTP Solar LLC	Solar Photovoltaic	9	23	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	3/23/2017	[redacted]
23	33R344	California Flats Solar Project	First Solar, Inc.	Solar Photovoltaic	150	381	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Complete	12/31/2018	[redacted]
24	33R330	RE Astoria LLC	Recurrent Energy	Solar Photovoltaic	100	298	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	1/3/2019	[redacted]
25	33R363	SR Solis Oro Loma Teresina, LLC- Project A	Con Edison Development	Solar Photovoltaic	10	26	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/17/2017	[redacted]
26	33R366	SR Solis Oro Loma Teresina, LLC- Project B	Con Edison Development	Solar Photovoltaic	10	26	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/17/2017	[redacted]
27	33R365	SR Solis Rocket, LLC - Project A	Con Edison Development	Solar Photovoltaic	8	20	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/17/2017	[redacted]
28	33R368	SR Solis Rocket, LLC - Project B	Con Edison Development	Solar Photovoltaic	8	20	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/17/2017	[redacted]
29	33R258	Blackwell Solar	First Solar, Inc.	Solar Photovoltaic	12	28	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	12/31/2019	[redacted]
30	33R256	Lost Hills Solar	First Solar, Inc.	Solar Photovoltaic	20	47	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	12/31/2019	[redacted]
31	33R343	Midway Solar Farm I	Solar Frontier Americas Holding, LLC	Solar Photovoltaic	50	119	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	6/1/2020	[redacted]

APPENDIX C.1a

Renewable Net Short Calculations – 33% RPS Target

January 14, 2016

Appendix C.1a - Renewable Net Short Calculations - 33% RPS Target

Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2015 - 2019) and LTPP Methodology (2020 - 2035)

Variable	Calculation	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Forecast	2016 Forecast	2014-2016	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast
		Forecast Year		-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Annual RPS Requirement																													
A		Bundled Retail Sales Forecast (LTPP)[1]		74,864	76,205	75,705	226,774	74,547	71,183	70,870	216,599	[redacted]	64,957	62,381	79,463	[redacted]	79,938	80,411	80,666	80,841	81,057	81,273	81,490	81,708	81,926	82,145	82,364	82,584	82,804	83,025	83,247
B		RPS Procurement Quantity Requirement (%)		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%
C	A*B	**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480	[redacted]	18,837	19,338	26,223	[redacted]	26,380	26,536	26,620	26,678	26,749	26,820	26,892	26,964	27,036	27,108	27,180	27,253	27,325	27,398	27,471
D		Voluntary Margin of Over-procurement[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D	**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480	[redacted]	18,837	19,338	26,223	[redacted]	26,380	26,536	26,620	26,678	26,749	26,820	26,892	26,964	27,036	27,108	27,180	27,253	27,325	27,398	27,471
		RPS-Eligible Procurement																													
Fa		Risk-Adjusted RECs from Online Generation[10]		14,699	14,513	17,212	46,424	20,206	22,092	21,967	64,265	21,693	19,728	19,038	18,198	78,656	17,772	15,361	15,028	14,760	14,648	14,084	13,842	13,791	13,235	13,170	12,807	12,280	11,060	10,060	9,276
Faa		Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb		Risk-Adjusted RECs from RPS Facilities in Development[11]		-	-	-	-	-	363	943	1,306	1,981	2,113	2,518	2,702	9,314	2,737	2,725	2,713	2,707	2,690	2,679	2,667	2,661	2,644	2,633	2,605	2,230	2,182	1,888	1,498
Fbb		Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	5.5%	3.2%	2.9%	1.5%	1.4%	1.2%	1.1%	1.3%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.3%	1.4%	0.6%
Fc		Pre-Approved Generic RECs		-	-	-	-	-	-	19	19	179	672	1,035	1,123	3,009	1,202	1,219	1,216	1,216	1,211	1,208	1,205	1,205	1,199	1,197	1,194	1,194	1,188	1,186	1,183
Fd		Executed REC Sales		-	-	(142)	(142)	(50)	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd	Total RPS Eligible Procurement (GWh)[9]		14,699	14,513	17,069	46,281	20,156	22,455	22,930	65,541	23,853	22,512	22,590	22,023	90,979	21,711	19,305	18,957	18,683	18,549	17,971	17,714	17,657	17,078	17,000	16,605	15,704	14,430	13,134	11,956
F0		Category 0 RECs		14,637	13,035	14,149	41,821	16,886	18,251	18,053	53,190	17,756	15,822	15,137	14,297	63,013	13,889	11,501	11,207	10,982	10,898	10,345	10,112	10,065	9,538	9,493	9,178	9,082	8,457	7,823	7,376
F1		Category 1 RECs		62	1,478	2,921	4,461	3,270	4,204	4,877	12,351	6,097	6,690	7,454	7,726	27,966	7,822	7,805	7,750	7,701	7,651	7,626	7,602	7,592	7,540	7,507	7,427	6,622	5,973	5,311	4,580
F2		Category 2 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3		Category 3 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Gross RPS Position (Physical Net Short)																													
Ga	F-E	**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,979	5,869	5,212	15,061	[redacted]	3,675	3,252	(4,200)	[redacted]	(4,668)	(7,230)	(7,662)	(7,995)	(8,200)	(8,849)	(9,178)	(9,306)	(9,957)	(10,108)	(10,575)	(11,548)	(12,895)	(14,265)	(15,515)
Gb	F/A	**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	31.5%	32.4%	30.3%	[redacted]	34.7%	36.2%	27.7%	[redacted]	27.2%	24.0%	23.5%	23.1%	22.9%	22.1%	21.7%	21.6%	20.8%	20.7%	20.2%	19.0%	17.4%	15.8%	14.4%
		Application of Bank																													
Ha	H - Hc (from previous year)	Existing Banked RECs above the PQR[3,4]		-	(274)	(1,033)	-	861	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hb		RECs above the PQR added to Bank		(274)	(728)	1,928	926	3,979	5,869	5,212	15,061	[redacted]	3,675	3,252	-	12,465	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hc		Non-bankable RECs above the PQR		-	31	34	65	26	22	71	119	83	-	-	-	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb	Gross Balance of RECs above the PQR		(274)	(1,002)	895	926	4,840	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ia		Planned Application of RECs above the PQR towards RPS Compliance[5]		-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ib		Planned Sales of RECs above the PQR[6]		-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J	H-Ia-Ib	Net Balance of RECs above the PQR[3]		(274)	(1,002)	895	926	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J0		Category 0 RECs		-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J1		Category 1 RECs		-	-	895	895	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J2		Category 2 RECs		-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Expiring Contracts																													
K		RECs from Expiring RPS Contracts[12]		N/A	N/A	N/A	N/A	-	0.4	518	518	1,011	1,642	3,866	4,732	11,250	5,071	7,433	7,728	8,014	8,028	8,555	8,760	8,818	9,286	9,315	9,656	10,564	11,728	12,962	14,090
		Net RPS Position (Optimized Net Short)																													
La	Ga + Ia – Ib – Hc	**Annual Net RPS Position after Bank Optimization (GWh)[7]**		(274)	(759)	1,894	861	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lb	(F + Ia – Ib – Hc)/A	**Annual Net RPS Position after Bank Optimization (%)[7,8]**		19.6%	19.0%	22.5%	20.4%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) LTPP sales forecast is not representative of PG&E's actual retail sales. Forecasts of retail sales for the first five years of the forecast were generated by PG&E's Load Forecasting and Research team at the beginning of each year, and may be updated throughout the year as additional data becomes available.

(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.

(3) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear larger than they are in Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.

(4) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(5) (Row Ia) The results in Ia are only applicable within the context of the stochastic model. Please see the Alternative RNS for the application of the bank.

(6) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.

(7) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(8) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization. PG&E has changed the formula in the Alternative RNS to (Ga+Ia-Ib+E)/A in order to express these values in a comparable way to the Physical Net Short (%) in Row Gb.

(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.

*Stochastic Results in Rows Ga-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

APPENDIX C.1b

Renewable Net Short Calculations – 40% RPS Scenario

January 14, 2016

Appendix C.1b - Renewable Net Short Calculations - 40% RPS Scenario

Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2015 - 2019) and LTPP Methodology (2020 - 2035)

Variable	Calculation	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Forecast	2016 Forecast	2014-2016	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast
		Forecast Year		-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Annual RPS Requirement																													
A		Bundled Retail Sales Forecast (LTPP)[1]		74,864	76,205	75,705	226,774	74,547	71,183	70,870	216,599	[redacted]	64,957	62,381	79,463	[redacted]	79,938	80,411	80,666	80,841	81,057	81,273	81,490	81,708	81,926	82,145	82,364	82,584	82,804	83,025	83,247
B		RPS Procurement Quantity Requirement (%)		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	33.0%	37.0%	37.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
C	A*B	**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480	[redacted]	18,837	19,338	26,223	[redacted]	26,380	29,752	29,846	32,336	32,423	32,509	32,596	32,683	32,770	32,858	32,946	33,034	33,122	33,210	33,299
D		Voluntary Margin of Over-procurement[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D	**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480	[redacted]	18,837	19,338	26,223	[redacted]	26,380	29,752	29,846	32,336	32,423	32,509	32,596	32,683	32,770	32,858	32,946	33,034	33,122	33,210	33,299
		RPS-Eligible Procurement																													
Fa		Risk-Adjusted RECs from Online Generation[10]		14,699	14,513	17,212	46,424	20,206	22,092	21,967	64,265	21,693	19,728	19,038	18,198	78,656	17,772	15,361	15,028	14,760	14,648	14,084	13,842	13,791	13,235	13,170	12,807	12,280	11,060	10,060	9,276
Faa		Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb		Risk-Adjusted RECs from RPS Facilities in Development[11]		-	-	-	-	-	363	943	1,306	1,981	2,113	2,518	2,702	9,314	2,737	2,725	2,713	2,707	2,690	2,679	2,667	2,661	2,644	2,633	2,605	2,230	2,182	1,888	1,498
Fbb		Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	5.5%	3.2%	2.9%	1.5%	1.4%	1.2%	1.1%	1.3%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.3%	1.4%	0.6%
Fc		Pre-Approved Generic RECs		-	-	-	-	-	-	19	19	179	672	1,035	1,123	3,009	1,202	1,219	1,216	1,216	1,211	1,208	1,205	1,205	1,199	1,197	1,194	1,194	1,188	1,186	1,183
Fd		Executed REC Sales		-	-	(142)	(142)	(50)	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd	Total RPS Eligible Procurement (GWh)[9]		14,699	14,513	17,069	46,281	20,156	22,455	22,930	65,541	23,853	22,512	22,590	22,023	90,979	21,711	19,305	18,957	18,683	18,549	17,971	17,714	17,657	17,078	17,000	16,605	15,704	14,430	13,134	11,956
F0		Category 0 RECs		14,637	13,035	14,149	41,821	16,886	18,251	18,053	53,190	17,756	15,822	15,137	14,297	63,013	13,889	11,501	11,207	10,982	10,898	10,345	10,112	10,065	9,538	9,493	9,178	9,082	8,457	7,823	7,376
F1		Category 1 RECs		62	1,478	2,921	4,461	3,270	4,204	4,877	12,351	6,097	6,690	7,454	7,726	27,966	7,822	7,805	7,750	7,701	7,651	7,626	7,602	7,592	7,540	7,507	7,427	6,622	5,973	5,311	4,580
F2		Category 2 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3		Category 3 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Gross RPS Position (Physical Net Short)																													
Ga	F-E	**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,979	5,869	5,212	15,061	[redacted]	3,675	3,252	(4,200)	[redacted]	(4,668)	(10,447)	(10,889)	(13,653)	(13,874)	(14,539)	(14,883)	(15,026)	(15,692)	(15,858)	(16,340)	(17,329)	(18,691)	(20,077)	(21,342)
Gb	F/A	**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	31.5%	32.4%	30.3%	[redacted]	34.7%	36.2%	27.7%	[redacted]	27.2%	24.0%	23.5%	23.1%	22.9%	22.1%	21.7%	21.6%	20.8%	20.7%	20.2%	19.0%	17.4%	15.8%	14.4%
		Application of Bank																													
Ha	H - Hc (from previous year)	Existing Banked RECs above the PQR[3,4]		-	(274)	(1,033)	-	861	[redacted]																						
Hb		RECs above the PQR added to Bank		(274)	(728)	1,928	926	3,979	5,869	5,212	15,061	[redacted]	3,675	3,252	-	12,465	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hc		Non-bankable RECs above the PQR		-	31	34	65	26	22	71	119	83	-	-	-	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb	Gross Balance of RECs above the PQR		(274)	(1,002)	895	926	4,840	[redacted]																						
Ia		Planned Application of RECs above the PQR towards RPS Compliance[5]		-	-	-	-	[redacted]																							
Ib		Planned Sales of RECs above the PQR[6]		-	-	-	-																								
J	H-Ia-Ib	Net Balance of RECs above the PQR[3]		(274)	(1,002)	895	926																								
J0		Category 0 RECs		-	-	-	-																								
J1		Category 1 RECs		-	-	895	895																								
J2		Category 2 RECs		-	-	-	-																								
		Expiring Contracts																													
K		RECs from Expiring RPS Contracts[12]		N/A	N/A	N/A	N/A	-	0.4	518	518	1,011	1,642	3,866	4,732	11,250	5,071	7,433	7,728	8,014	8,028	8,555	8,760	8,818	9,286	9,315	9,656	10,564	11,728	12,962	14,090
		Net RPS Position (Optimized Net Short)																													
La	Ga + Ia – Ib – Hc	**Annual Net RPS Position after Bank Optimization (GWh)[7]**		(274)	(759)	1,894	861	[redacted]																							
Lb	(F + Ia – Ib – Hc)/A	**Annual Net RPS Position after Bank Optimization (%)[7,8]**		19.6%	19.0%	22.5%	20.4%																								

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) LTPP sales forecast is not representative of PG&E's actual retail sales. Forecasts of retail sales for the first five years of the forecast were generated by PG&E's Load Forecasting and Research team at the beginning of each year, and may be updated throughout the year as additional data becomes available.

(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.

(3) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear larger than they are in Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.

(4) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(5) (Row Ia) The results in Ia are only applicable within the context of the stochastic model. Please see the Alternative RNS for the application of the bank.

(6) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.

(7) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(8) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization. PG&E has changed the formula in the Alternative RNS to (Ga+Ia-Ib+E)/A in order to express these values in a comparable way to the Physical Net Short (%) in Row Gb.

(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.

*Stochastic Results in Rows Ga-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

APPENDIX C.2a

Alternate Renewable Net Short Calculations – 33% RPS Target

January 14, 2016

Appendix C.2a - Alternate Renewable Net Short Calculations – 33% RPS Target

Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	**2011-2013**	2014 Actuals	2015 Forecast	2016 Forecast	**2014-2016**	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	**2017-2020**	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast
			Forecast Year		-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Annual RPS Requirement																													
A			Bundled Retail Sales Forecast (Alternate)[1]		74,864	76,205	75,705	226,774	74,547	71,183	70,870	216,599		64,957	62,381	59,668		59,780	59,888	59,988	60,077	60,189	60,407	60,765	61,331	62,067	62,948	64,033	65,355	66,902	68,683	69,892
B			RPS Procurement Quantity Requirement (%)		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%
C	A*B		**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480		18,837	19,338	19,690		19,727	19,763	19,796	19,825	19,862	19,934	20,052	20,239	20,482	20,773	21,131	21,567	22,078	22,665	23,064
D			Voluntary Margin of Over-procurement[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D		**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480		18,837	19,338	19,690		19,727	19,763	19,796	19,825	19,862	19,934	20,052	20,239	20,482	20,773	21,131	21,567	22,078	22,665	23,064
			RPS-Eligible Procurement																													
Fa			Risk-Adjusted RECs from Online Generation[10]		14,699	14,513	17,212	46,424	20,206	22,092	21,967	64,265	21,693	19,728	19,038	18,198	78,656	17,772	15,361	15,028	14,760	14,648	14,084	13,842	13,791	13,235	13,170	12,807	12,280	11,060	10,060	9,276
Faa			Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[11]		-	-	-	-	-	363	943	1,306	1,981	2,113	2,518	2,702	9,314	2,737	2,725	2,713	2,707	2,690	2,679	2,667	2,661	2,644	2,633	2,605	2,230	2,182	1,888	1,498
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	5.5%	3.2%	2.9%	1.5%	1.4%	1.2%	1.1%	1.3%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.3%	1.4%	0.6%
Fc			Pre-Approved Generic RECs		-	-	-	-	-	-	19	19	179	672	1,035	1,123	3,009	1,202	1,219	1,216	1,216	1,211	1,208	1,205	1,205	1,199	1,197	1,194	1,194	1,188	1,186	1,183
Fd			Executed REC Sales		-	-	(142)	(142)	(50)	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd		Total RPS Eligible Procurement (GWh)[9]		14,699	14,513	17,069	46,281	20,156	22,455	22,930	65,541	23,853	22,512	22,590	22,023	90,979	21,711	19,305	18,957	18,683	18,549	17,971	17,714	17,657	17,078	17,000	16,605	15,704	14,430	13,134	11,956
F0			Category 0 RECs		14,637	13,035	14,149	41,821	16,886	18,251	18,053	53,190	17,756	15,822	15,137	14,297	63,013	13,889	11,501	11,207	10,982	10,898	10,345	10,112	10,065	9,538	9,493	9,178	9,082	8,457	7,823	7,376
F1			Category 1 RECs		62	1,478	2,921	4,461	3,270	4,204	4,877	12,351	6,097	6,690	7,454	7,726	27,966	7,822	7,805	7,750	7,701	7,651	7,626	7,602	7,592	7,540	7,507	7,427	6,622	5,973	5,311	4,580
F2			Category 2 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Step 1 Result: Physical Net Short3																													
Ga	F-E		**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,979	5,869	5,212	15,061		3,675	3,252	2,332		1,984	(458)	(839)	(1,142)	(1,314)	(1,964)	(2,339)	(2,582)	(3,404)	(3,773)	(4,526)	(5,863)	(7,647)	(9,532)	(11,108)
Gb	F/A		**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	31.5%	32.4%	30.3%		34.7%	36.2%	36.9%		36.3%	32.2%	31.6%	31.1%	30.8%	29.7%	29.2%	28.8%	27.5%	27.0%	25.9%	24.0%	21.6%	19.1%	17.1%

PG&E's Alternative RNS Table - Stochastic-Adjustment (2011-2035)

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013 Actuals	2014 Actuals	2015 Forecast	2016 Forecast	**2014-2016**	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	**2017-2020**	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast
			Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[4]																													
Gd			**Stochastically-Adjusted Annual Gross RPS Position (GWh)**					926																								
Ge			**Stochastically-Adjusted Annual Gross RPS Position (%)**					20.4%																								
			Application of Bank																													
Ha	H - Hc (from previous year	J - Hc (from previous year)	Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[5,6]					0				861																				
Hb			RECs above the PQR added to Bank					926																								
Hc			Non-bankable RECs above the PQR					65				119					83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb		Gross Balance of RECs above the PQR					926		Optimization is Based on Compliance Period Only				Optimization is Based on Compliance Period Only																		
Ia			Planned Application of RECs above the PQR towards RPS Compliance					-																								
Ib			Planned Sales of RECs above the PQR[7]					-																								
J	H-Ia-Ib		Net Balance of RECs above the PQR (The Bank at End of Period)[5]					926																								
J0			Category 0 RECs					-																								
J1			Category 1 RECs					926																								
J2			Category 2 RECs					-																								
			Expiring Contracts																													
K			RECs from Expiring RPS Contracts[12]		N/A	N/A	N/A	N/A	-	0.4	518	518	1,011	1,642	3,866	4,732	11,250	5,071	7,433	7,728	8,014	8,028	8,555	8,760	8,818	9,286	9,315	9,656	10,564	11,728	12,962	14,090
			Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[8]																													
La	Ga + Ia – Ib – Hc	Gd+Ia-Ib	**Annual Net RPS Position after Bank Optimization (GWh)**					926		Optimization is Based on Compliance Period Only				Optimization is Based on Compliance Period Only																		
Lb	(F + Ia – Ib – Hc)/A	(Gd+Ia-Ib+E)/A	**Annual Net RPS Position after Bank Optimization (%)**					20.4%																								

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) PG&E uses its April 30, 2015 internal alternative load forecast for its procurement decisions.†

(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.

(3) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the LTPP forecast provided in the RNS.

(4) (Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2015 RPS Plan.
This is prior to any application of the Bank.

(5) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.

(6) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(7) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.

(8) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

(c) PG&E includes the non-bankable volumes in calculating rows La and Lb. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.

*Stochastic Results in Rows Gd-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

APPENDIX C.2b

Alternate Renewable Net Short Calculations – 40% RPS Scenario

January 14, 2016

Appendix C.2b - Alternate Renewable Net Short Calculations - 40% RPS Scenario

Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Forecast	2016 Forecast	2014-2016	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast
			Forecast Year		-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Annual RPS Requirement																													
A			Bundled Retail Sales Forecast (Alternate)[1]		74,864	76,205	75,705	226,774	74,547	71,183	70,870	216,599	[redacted]	64,957	62,381	59,668	[redacted]	59,780	59,888	59,988	60,077	60,189	60,407	60,765	61,331	62,067	62,948	64,033	65,355	66,902	68,683	69,892
B			RPS Procurement Quantity Requirement (%)		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	33.0%	37.0%	37.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
C	A*B		**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480	[redacted]	18,837	19,338	19,690	[redacted]	19,727	22,159	22,195	24,031	24,075	24,163	24,306	24,532	24,827	25,179	25,613	26,142	26,761	27,473	27,957
D			Voluntary Margin of Over-procurement[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D		**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,586	17,717	50,480	[redacted]	18,837	19,338	19,690	[redacted]	19,727	22,159	22,195	24,031	24,075	24,163	24,306	24,532	24,827	25,179	25,613	26,142	26,761	27,473	27,957
			RPS-Eligible Procurement																													
Fa			Risk-Adjusted RECs from Online Generation[10]		14,699	14,513	17,212	46,424	20,206	22,092	21,967	64,265	21,693	19,728	19,038	18,198	78,656	17,772	15,361	15,028	14,760	14,648	14,084	13,842	13,791	13,235	13,170	12,807	12,280	11,060	10,060	9,276
Faa			Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[11]		-	-	-	-	-	363	943	1,306	1,981	2,113	2,518	2,702	9,314	2,737	2,725	2,713	2,707	2,690	2,679	2,667	2,661	2,644	2,633	2,605	2,230	2,182	1,888	1,498
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	5.5%	3.2%	2.9%	1.5%	1.4%	1.2%	1.1%	1.3%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.3%	1.4%	0.6%
Fc			Pre-Approved Generic RECs		-	-	-	-	-	-	19	19	179	672	1,035	1,123	3,009	1,202	1,219	1,216	1,216	1,211	1,208	1,205	1,205	1,199	1,197	1,194	1,194	1,188	1,186	1,183
Fd			Executed REC Sales		-	-	(142)	(142)	(50)	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd		Total RPS Eligible Procurement (GWh)[9]		14,699	14,513	17,069	46,281	20,156	22,455	22,930	65,541	23,853	22,512	22,590	22,023	90,979	21,711	19,305	18,957	18,683	18,549	17,971	17,714	17,657	17,078	17,000	16,605	15,704	14,430	13,134	11,956
F0			Category 0 RECs		14,637	13,035	14,149	41,821	16,886	18,251	18,053	53,190	17,756	15,822	15,137	14,297	63,013	13,889	11,501	11,207	10,982	10,898	10,345	10,112	10,065	9,538	9,493	9,178	9,082	8,457	7,823	7,376
F1			Category 1 RECs		62	1,478	2,921	4,461	3,270	4,204	4,877	12,351	6,097	6,690	7,454	7,726	27,966	7,822	7,805	7,750	7,701	7,651	7,626	7,602	7,592	7,540	7,507	7,427	6,622	5,973	5,311	4,580
F2			Category 2 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Step 1 Result: Physical Net Short3																													
Ga	F-E		**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,979	5,869	5,212	15,061	[redacted]	3,675	3,252	2,332	[redacted]	1,984	(2,853)	(3,238)	(5,348)	(5,527)	(6,192)	(6,592)	(6,875)	(7,748)	(8,179)	(9,008)	(10,438)	(12,331)	(14,340)	(16,000)
Gb	F/A		**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	31.5%	32.4%	30.3%	[redacted]	34.7%	36.2%	36.9%	[redacted]	36.3%	32.2%	31.6%	31.1%	30.8%	29.7%	29.2%	28.8%	27.5%	27.0%	25.9%	24.0%	21.6%	19.1%	17.1%

PG&E's Alternative RNS Table - Stochastic-Adjustment (2011-2035)

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013 Actuals	2014 Actuals	2015 Forecast	2016 Forecast	2014-2016	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast
			Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[4]																													
Gd			**Stochastically-Adjusted Annual Gross RPS Position (GWh)**					926	Optimization is Based on Compliance Period Only			[redacted]	Optimization is Based on Compliance Period Only				[redacted]															
Ge			**Stochastically-Adjusted Annual Gross RPS Position (%)**					20.4%				[redacted]					[redacted]															
			Application of Bank									[redacted]					[redacted]															
Ha	H - Hc (from previous year)	J - Hc (from previous year)	Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[5,6]					-				861					[redacted]															
Hb			RECs above the PQR added to Bank					926				[redacted]					[redacted]															
Hc			Non-bankable RECs above the PQR					65				119					83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb		Gross Balance of RECs above the PQR					926				[redacted]					[redacted]															
Ia			Planned Application of RECs above the PQR towards RPS Compliance					-				[redacted]					[redacted]															
Ib			Planned Sales of RECs above the PQR[7]					-				[redacted]					[redacted]															
J	H-Ia-Ib		Net Balance of RECs above the PQR (The Bank at End of Period)[5]					926				[redacted]					[redacted]															
J0			Category 0 RECs					-				[redacted]					[redacted]															
J1			Category 1 RECs					926				[redacted]					[redacted]															
J2			Category 2 RECs					-				[redacted]					[redacted]															
			Expiring Contracts																													
K			RECs from Expiring RPS Contracts[12]		N/A	N/A	N/A	N/A	-	0.4	518	518	1,011	1,642	3,866	4,732	11,250	5,071	7,433	7,728	8,014	8,028	8,555	8,760	8,818	9,286	9,315	9,656	10,564	11,728	12,962	14,090
			Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[8]																													
La	Ga + Ia – Ib – Hc	Gd+Ia-Ib	**Annual Net RPS Position after Bank Optimization (GWh)**					926	Optimization is Based on Compliance Period Only			[redacted]	Optimization is Based on Compliance Period Only				[redacted]															
Lb	(F + Ia – Ib – Hc)/A	(Gd+Ia-Ib+E)/A	**Annual Net RPS Position after Bank Optimization (%)**					20.4%				[redacted]					[redacted]															

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) PG&E uses its April 30, 2015 internal alternative load forecast for its procurement decisions.†

(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2015 RPS Plan for a description of PG&E's VMOP.

(3) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the LTPP forecast provided in the RNS.

(4) (Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2015 RPS Plan.

This is prior to any application of the Bank.

(5) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.

(6) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(7) (Row Ib) The purpose of the planned sales is to minimize the non-bankable volumes, but the actual sales could be a combination of bankable and non-bankable volumes.

(8) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

(c) PG&E includes the non-bankable volumes in calculating rows La and Lb. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(9) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(10) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(11) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(12) (Row K) Row K now includes only expiring volumes from contracts as of April 30, 2015.

*Stochastic Results in Rows Gd-Lb reflect a April 30, 2015 stochastic modeling vintage.

†Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, Rulemaking ("R.") 13-12-010, filed December 19, 2013.

APPENDIX D

Procurement Information Related to Cost Quantification

January 14, 2016

Appendix D – Procurement Information Related to Cost Quantification

Assumptions	
Table 1 (Actual Costs, $) Items	**Actual**
Rows 2 -- 8, 11 (2003-2014)[1, 2, 3, 4, 5, 6]	Settled contract costs with all RPS-eligible contracts in PG&E's portfolio for 2003-2014
Row 9	For 2003-2011, capital costs are based on the net book value of PG&E's RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For 2012 through 2014, capital costs are based on the net book value of PG&E's RPS-eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-2014) were added to each year's capital costs to calculate total costs.
Row 10	LCOE for each project multiplied by the project's historical generation
Row 13	PG&E actual bundled retail sales
Row 14	Total Cost / Bundled Retail Sales (Row 12 / Row 13)
Table 2 (Forecast Costs, $) Items	**Forecast**
Rows 2 -- 8, 11, 16 -- 22, 25	PG&E's future expenditures on all RPS-eligible procurement and generation either (1) approved to date or (2) executed prior to April 2015 but pending CPUC approval. 2015 data represent a September 2014 vintage and 2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR).
Rows 9 and 23	For 2015-2030, annualized capital costs based on the net book value of PG&E's RPS-eligible units as of December 2014 were added to operation and maintenance (O&M) costs, which were calculated as 2014 O&M costs escalated at 5% annually for each year.
Row 10 and 24	LCOE for each project multiplied by the project's forecasted generation
Rows 13 and 27	PG&E bundled retail sales forecast
Rows 14 and 28	Total Cost / Bundled Sales
Row 29	Row 14 + Row 28
Table 3 (Actual Generation, MWh) Items	**Actual**
Rows 2 -- 11[1, 3, 4, 5, 6]	Generation (MWh) associated with payments for RPS-eligible deliveries
Table 4 (Forecast Generation, MWh) Items	**Forecast**
Rows 2 -- 11 and 16-25	Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to April 2015 but pending Commission approval -- assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. 2015 data represent a September 2014 vintage and 2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR).

[1] 2014 Generation and Costs were updated to reflect best available data as of March 2015.

[2] Row 5 includes the aggregate costs (specifically debt service and operation and maintenance) of PG&E's contract with Solano Irrigation District (SID) who supplies power from multiple hydro units, 100% of which are RPS-eligible. SID's costs include the costs to operate and maintain the hydro units and project facilities (dams and waterways). Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost data is not relevant and thereby not included.

[3] RPS-eligible generation reported in 2014 is the best available settlements data as of March 2015 and therefore contains actual data as settlements data for the prior year can continue to be adjusted after January of the current year. As UOG Hydro and UOG Solar estimates are calculated separately, 2013 data for these two technology types is the best available as of April 2014.

[4] Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.

[5] Cost for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract.

[6] Some immaterial changes have been made to cost and generation data from 2005, 2011, and 2013 as compared to the 2014 RPS Plan. 2005 changes are due to a 2006 RPS wind contract being accidently included in 2005. 2011 data changes are due to a mislabeling of a biogas contract as biomass. 2013 changes represent updated settlements data.

Note: As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 1
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs											
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
2	Biogas	$25,762	$23,856	$25,623	$22,823	$24,126	$23,468	$27,306	$20,216	$16,776	$5,333	$5,063	$11,087
3	Biomass	$215,078	$217,923	$217,279	$222,125	$238,524	$259,957	$262,086	$263,994	$245,622	$302,711	$299,205	$317,301
4	Geothermal	$110,572	$111,778	$108,720	$118,523	$199,143	$282,227	$200,357	$260,053	$223,575	$209,854	$284,334	$324,050
5	Small Hydro	$60,984	$57,470	$80,340	$97,340	$63,161	$72,488	$52,053	$63,296	$84,864	$54,140	$57,213	$45,522
6	Solar PV	$0	$0	$0	$0	$0	$0	$2,554	$10,180	$33,370	$176,372	$504,860	$803,806
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,698	$173,856
8	Wind	$65,244	$74,912	$56,891	$67,116	$98,203	$102,516	$199,475	$224,089	$340,517	$379,416	$424,764	$437,159
9	UOG Small Hydro	$44,936	$45,059	$46,526	$47,556	$47,933	$49,009	$47,567	$49,684	$52,099	$51,572	$64,691	$66,066
10	UOG Solar	$0	$0	$0	$0	$227	$452	$473	$1,498	$5,620	$27,093	$43,882	$52,426
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0				
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$522,576**	**$530,998**	**$535,380**	**$575,483**	**$671,317**	**$790,116**	**$791,870**	**$893,010**				
13	Bundled Retail Sales [Thousands of kWh]	71,099,363	72,113,608	72,371,532	76,356,279	79,078,319	81,523,859	79,624,479	77,485,129	74,863,941	76,205,120	75,705,039	74,546,865
14	**Incremental Rate Impact**[2]	**0.73 ¢/kWh**	**0.74 ¢/kWh**	**0.74 ¢/kWh**	**0.75 ¢/kWh**	**0.85 ¢/kWh**	**0.97 ¢/kWh**	**0.99 ¢/kWh**	**1.15 ¢/kWh**				

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row. For example, the cost of an Unbundled REC procured from a wind facility is only reported in the Unbundled RECs row.

[2] Incremental Rate Impact is equal to Row 12 divided by Row 13. While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs					
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
13	Bundled Retail Sales [Thousands of kWh]	71,182,544	70,869,576	[redacted]	64,956,724	62,381,387	59,668,061
14	**Incremental Rate Impact[2]**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	$22,780	$23,189	$29,915	$29,994	$29,986	$30,143
17	Biomass	$311,380	$270,577	$241,040	$219,990	$193,377	$136,275
18	Geothermal	$329,015	$311,371	$314,874	$193,171	$194,611	$196,294
19	Small Hydro	$76,539	$71,939	$62,257	$55,181	$52,386	$43,648
20	Solar PV	$887,525	$914,533	$970,536	$974,319	$1,000,120	$1,019,418
21	Solar Thermal	$329,978	$329,961	$329,165	$328,838	$328,759	$330,446
22	Wind	$449,274	$432,664	$427,910	$425,276	$408,949	$409,845
23	UOG Small Hydro	$67,407	$68,815	$70,294	$71,847	$73,477	$75,189
24	UOG Solar	$51,674	$51,406	$51,139	$50,874	$50,610	$50,347
25	Unbundled RECs[1]	[redacted]	$0	$0	$0	$0	$0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	[redacted]	**$2,474,455**	**$2,497,131**	**$2,349,489**	**$2,332,276**	**$2,291,605**
27	Bundled Retail Sales [Thousands of kWh]	71,182,544	70,869,576	[redacted]	64,956,724	62,381,387	59,668,061
28	**Incremental Rate Impact[2]**	[redacted]	**3.49 ¢/kWh**	[redacted]	**3.62 ¢/kWh**	**3.74 ¢/kWh**	**3.84 ¢/kWh**
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	[redacted]	**3.49 ¢/kWh**	[redacted]	**3.62 ¢/kWh**	**3.74 ¢/kWh**	**3.84 ¢/kWh**

[1] See footnote 1 from Table 1.

[2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs									
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
13	Bundled Retail Sales [Thousands of kWh]	59,779,916	59,888,425	59,987,654	60,077,196	60,188,640	60,407,333	60,765,057	61,330,567	62,066,738	62,947,785
14	**Incremental Rate Impact**[2]	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
16	Biogas	$30,098	$30,190	$30,175	$29,839	$29,408	$29,107	$29,167	$29,288	$27,193	$26,884
17	Biomass	$127,551	$128,345	$129,109	$130,224	$130,865	$131,575	$99,946	$95,123	$95,038	$95,228
18	Geothermal	$196,819	$13,563	$13,470	$13,423	$13,314	$13,256	$13,174	$13,121	$12,997	$12,921
19	Small Hydro	$35,937	$29,846	$29,039	$29,202	$28,968	$29,258	$29,666	$29,695	$24,716	$24,619
20	Solar PV	$1,015,955	$1,013,201	$1,009,278	$1,007,457	$1,004,547	$1,005,450	$1,001,743	$1,000,015	$992,076	$988,605
21	Solar Thermal	$329,547	$329,514	$329,165	$329,232	$329,063	$329,978	$329,547	$329,639	$328,838	$328,759
22	Wind	$403,463	$397,706	$378,153	$353,862	$351,789	$287,146	$287,350	$288,065	$251,628	$250,960
23	UOG Small Hydro	$76,987	$78,874	$80,856	$82,937	$85,122	$87,416	$89,825	$92,354	$95,010	$97,798
24	UOG Solar	$50,086	$49,826	$49,568	$49,311	$49,055	$48,801	$48,548	$48,296	$48,045	$47,796
25	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	**$2,266,444**	**$2,071,066**	**$2,048,814**	**$2,025,487**	**$2,022,129**	**$1,961,985**	**$1,928,966**	**$1,925,595**	**$1,875,541**	**$1,873,571**
27	Bundled Retail Sales [Thousands of kWh]	59,779,916	59,888,425	59,987,654	60,077,196	60,188,640	60,407,333	60,765,057	61,330,567	62,066,738	62,947,785
28	**Incremental Rate Impact**[2]	**3.79 ¢/kWh**	**3.46 ¢/kWh**	**3.42 ¢/kWh**	**3.37 ¢/kWh**	**3.36 ¢/kWh**	**3.25 ¢/kWh**	**3.17 ¢/kWh**	**3.14 ¢/kWh**	**3.02 ¢/kWh**	**2.98 ¢/kWh**
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	**3.79 ¢/kWh**	**3.46 ¢/kWh**	**3.42 ¢/kWh**	**3.37 ¢/kWh**	**3.36 ¢/kWh**	**3.25 ¢/kWh**	**3.17 ¢/kWh**	**3.14 ¢/kWh**	**3.02 ¢/kWh**	**2.98 ¢/kWh**

[1] See footnote 1 from Table 1.

[2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled “Incremental Rate Impact,” the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable “premium.” In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 3
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)											
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
2	Biogas	364,745	333,897	366,514	300,943	293,147	280,795	342,362	306,909	284,129	112,153	85,706	112,161
3	Biomass	2,839,795	2,961,633	2,858,643	2,770,398	2,751,813	2,813,819	3,122,048	2,990,615	3,043,656	3,158,131	3,055,370	3,226,904
4	Geothermal	1,674,702	1,753,043	1,687,360	1,790,870	2,701,970	3,350,232	3,411,798	3,766,700	3,780,954	3,807,728	3,687,236	3,870,952
5	Small Hydro	1,269,233	1,096,183	1,457,339	1,760,707	927,879	945,921	937,626	1,092,707	1,457,714	863,606	652,953	400,300
6	Solar PV	6	4	4	3	1	1	21,706	58,593	179,171	1,006,145	3,358,366	5,266,030
7	Solar Thermal	0	0	0	0	0	0	0	0	0	0	20,581	878,905
8	Wind	940,239	1,078,579	874,204	1,019,451	1,374,337	1,439,796	2,557,988	2,981,660	4,395,377	4,515,452	4,924,052	5,358,546
9	UOG Small Hydro	1,382,934	1,267,084	1,403,130	1,437,196	984,607	993,266	1,103,017	1,157,077	1,254,638	948,734	1,394,189	1,292,552
10	UOG Solar	0	0	0	0	225	445	504	4,642	26,790	165,656	279,500	336,905
11	Unbundled RECs[2]	0	0	0	0	0	0	0	0	102,888	108,874	101,256	100,581
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11]	8,471,654	8,490,423	8,647,195	9,079,568	9,033,979	9,824,276	11,497,048	12,358,903	14,525,317	14,686,479	17,559,209	20,843,836

[1] Energy Volumes reported for 2014 in Rows 2 – 11 are the best available settlements data as of March 2015.

[2] Row 11 only includes Unbundled RECs with CPUC approval.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries 2015-2020 (MWh)					
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11]	0	0	0	0	0	0
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	213,398	215,310	267,185	267,182	266,495	266,549
17	Biomass	3,040,682	2,872,745	2,656,538	2,351,353	1,955,668	1,217,664
18	Geothermal	3,940,027	3,846,522	3,835,023	2,319,523	2,318,615	2,324,132
19	Small Hydro	1,055,888	919,433	830,771	756,106	709,157	612,327
20	Solar PV	6,034,593	6,312,470	7,065,526	7,111,196	7,454,367	7,611,582
21	Solar Thermal	1,780,838	1,783,858	1,780,838	1,780,838	1,780,838	1,783,858
22	Wind	5,712,775	5,479,845	5,383,493	5,327,732	5,122,748	5,121,450
23	UOG Small Hydro	1,251,112	1,151,280	1,361,309	1,433,494	1,457,994	1,470,682
24	UOG Solar	343,413	330,121	327,677	325,972	324,276	323,304
25	Unbundled RECs	100,000	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25]	23,472,725	22,911,584	23,508,361	21,673,397	21,390,159	20,731,551

Joint IOU Cost Quantification Table 4 (continued)
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries 2021-2030 (MWh)									
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	0	0	0	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0	0	0	0	0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11]	0	0	0	0	0	0	0	0	0	0
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
16	Biogas	265,270	265,284	264,803	261,746	256,235	251,874	251,827	252,519	240,795	238,613
17	Biomass	1,090,072	1,090,072	1,090,072	1,092,821	1,090,072	1,087,042	882,505	851,855	849,722	849,722
18	Geothermal	2,316,815	152,229	151,342	150,941	149,584	148,713	147,846	147,454	146,129	145,278
19	Small Hydro	498,763	413,322	392,430	391,039	384,319	383,913	383,483	378,818	333,264	328,828
20	Solar PV	7,598,989	7,550,029	7,501,666	7,469,194	7,405,927	7,358,546	7,311,489	7,279,915	7,199,970	7,147,369
21	Solar Thermal	1,780,838	1,780,838	1,780,838	1,783,858	1,780,838	1,780,838	1,780,838	1,783,858	1,780,838	1,780,838
22	Wind	4,997,701	4,883,296	4,609,823	4,358,250	4,326,117	3,808,664	3,808,664	3,816,232	3,392,738	3,382,295
23	UOG Small Hydro	1,467,619	1,467,824	1,467,546	1,470,461	1,466,095	1,468,461	1,466,608	1,471,677	1,463,931	1,468,041
24	UOG Solar	320,911	319,242	317,581	316,629	314,286	312,651	311,025	310,093	307,798	306,197
25	Unbundled RECs	0	0	0	0	0	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25]	20,336,980	17,922,135	17,576,101	17,294,939	17,173,473	16,600,702	16,344,285	16,292,421	15,715,185	15,647,181

APPENDIX E

RPS-Eligible Contracts Expiring 2015-2025

January 14, 2016

Appendix E – RPS–Eligible Contracts Expiring 2015–2025

Log Number	Project Name	Facility Name	Contract Expiration Year	MW	Expected Annual Generation (GWh)	Contract Type	Resource Type	City	State
01W004	Green Ridge Power LLC (110 MW)	Green Ridge Power LLC (110 MW)	2015	144.1	NA	Qualifying Facility (QF)	Wind	Livermore	CA
01W018	Green Ridge Power LLC (5.9 MW)	Green Ridge Power LLC (5.9 MW)	2015	5.9	NA	Qualifying Facility (QF)	Wind	Tracy	CA
01W035	Green Ridge Power LLC (70 MW)	Green Ridge Power LLC (70 MW)	2015	54	NA	Qualifying Facility (QF)	Wind	Tracy	CA
01W146A	Green Ridge Power LLC (100 MW – A)	Green Ridge Power LLC (100 MW – A)	2015	43.1	NA	Qualifying Facility (QF)	Wind	Tracy	CA
01W146D	Green Ridge Power LLC (100 MW – D)	Green Ridge Power LLC (100 MW – D)	2015	15	NA	Qualifying Facility (QF)	Wind	Tracy	CA
04H061QPA2	Indian Valley Hydro (PURPA)	Indian Valley Hydro	2015	3	13.11875	QF/CHP Summit	Hydro: Small	Clearlake Oaks	CA
10G012QPA	Amedee Geothermal Venture 1 PURPA	Amedee Geothermal Venture 1	2015	0.69	3.5	QF/CHP Summit	Geothermal	Wendel	CA
16W011	Green Ridge Power LLC (23.8 MW)	Green Ridge Power LLC (23.8 MW)	2015	10.8	NA	Qualifying Facility (QF)	Wind	Tracy	CA
16W014	Altamont Power LLC (3-4)	Altamont Power LLC (3-4)	2015	4.05	NA	Qualifying Facility (QF)	Wind	Tracy	CA
16W015	Altamont Power LLC (4-4)	Altamont Power LLC (4-4)	2015	19	NA	Qualifying Facility (QF)	Wind	Tracy	CA
16W028	Patterson Pass Wind Farm LLC	Patterson Pass Wind Farm	2015	22	NA	Qualifying Facility (QF)	Wind	Tracy	CA
25C013	Covanta Mendota L. P.	Mendota Biomass Power	2015	25	NA	Qualifying Facility (QF)	Biomass	Mendota	CA
04P010	Gas Recovery Sys. (American Cyn)	American Canyon	2016	1.5	NA	Qualifying Facility (QF)	Biogas Generation	American Canyon	CA
10C003	Collins Pine	Collins Pine	2016	12	NA	Qualifying Facility (QF)	Biomass	Chester	CA
10H002	Lassen Station Hydro	Lassen Station Hydro	2016	0.99	NA	Qualifying Facility (QF)	Hydro: Small	Oroville	CA
10H013	Hypower, Inc.	Hypower, Inc.	2016	10.8	NA	Qualifying Facility (QF)	Hydro: Small	De Sabla	CA
12H006	Yuba County Water Agency (Fish Release)	Yuba County Water Agency (Fish Release)	2016	0.15	NA	Qualifying Facility (QF)	Hydro: Small	Dobbins	CA
13H008	Arbuckle Mountain Hydro	Arbuckle Mountain Hydro	2016	0.3	NA	Qualifying Facility (QF)	Hydro: Small	Platina	CA
13H014	Mega Renewables (Roaring Crk)	Roaring Crk	2016	2	NA	Qualifying Facility (QF)	Hydro: Small	Montgomery Creek	CA
13H040	Tko Power (South Fork Bear Creek)	South Fork Bear Creek	2016	3	NA	Qualifying Facility (QF)	Hydro: Small	Shingletown	CA
13H125	Mega Hydro #1 (Clover Creek)	Mega Hydro #1 (Clover Creek)	2016	1	NA	Qualifying Facility (QF)	Hydro: Small	Oak Run	CA
16H003	Tri-Dam Authority	Tri-Dam Authority	2016	16.2	NA	Qualifying Facility (QF)	Hydro: Small	Strawberry	CA
16W017	Altamont Power LLC (6-4)	Altamont Power LLC (6-4)	2016	19	NA	Qualifying Facility (QF)	Wind	Tracy	CA
33R009	Diablo Winds	Diablo Winds	2016	18	65	RPS	Wind	Livermore	CA
04H011	Far West Power Corporation	Far West Power Corporation	2017	0.4	NA	Qualifying Facility (QF)	Hydro: Small	Potter Valley	CA
06W148	Edf Renewable Windfarm V, Inc. (10 MW)	EDF Renewable Windfarm V, Inc. (10 MW)	2017	10	NA	Qualifying Facility (QF)	Wind	Suisun City	CA
13C038	Burney Forest Products	Burney Facility	2017	31	NA	Qualifying Facility (QF)	Biomass	Burney	CA
13H001	El Dorado Hydro LLC (Montgomery Creek)	El Dorado Irrigation District	2017	2.6	NA	Qualifying Facility (QF)	Hydro: Small	Pollock Pines	CA
13H015	Mega Renewables (Hatchet Crk)	Hatchet Crk	2017	7	NA	Qualifying Facility (QF)	Hydro: Small	Montgomery Creek	CA
13H017	Mega Renewables (Bidwell Ditch)	Bidwell Ditch	2017	2	NA	Qualifying Facility (QF)	Hydro: Small	Burney	CA
13H036	Mega Renewables (Silver Springs)	Silver Springs	2017	0.6	NA	Qualifying Facility (QF)	Hydro: Small	Big Bend	CA
16P002	Pacific-Ultrapower Chinese Station	Ogden Power Pacific, Inc. (Chinese Station)	2017	22	NA	Qualifying Facility (QF)	Biomass	Jamestown	CA
19P005	DG Fairhaven Power, LLC	DG Fairhaven Power, LLC	2017	17.25	NA	Qualifying Facility (QF)	Biomass	Fairhaven	CA
33R012	Buena Vista	Buena Vista Energy	2017	43	108	RPS	Wind	Byron	CA
33R252	PCWA (RPS) – French Meadows / Oxbow / Hell Hole	Multiple	2017	24.6	93	RPS	Hydro: Small	Multiple	Multiple
06W146C	Edf Renewable Windfarm V, Inc. (70 MW – C)	EDF Renewable Windfarm V, Inc. (70 MW – C)	2018	6.5	NA	Qualifying Facility (QF)	Wind	Suisun City	CA
08H013	Santa Clara Valley Water Dist.	Santa Clara Valley Water Dist.	2018	0.8	NA	Qualifying Facility (QF)	Hydro: Small	Morgan Hill	CA
13H042	Nelson Creek Power Inc.	Nelson Creek Power Inc.	2018	1.1	NA	Qualifying Facility (QF)	Hydro: Small	Big Bend	CA
13P045	Wheelabrator Shasta	Wheelabrator Shasta	2018	54.9	NA	Qualifying Facility (QF)	Biomass	Anderson	CA
25W105	International Turbine Research	International Turbine Research	2018	34	NA	Qualifying Facility (QF)	Wind	Pacheco Pass	CA
33R038	Wadham Energy LP	Wadham	2018	26.5	141	RPS	Biomass	Williams	CA
10H010	Five Bears Hydroelectric	Five Bears Hydroelectric	2019	0.99	NA	Qualifying Facility (QF)	Hydro: Small	Genesee Valley	CA
10P005	HL Power	HL Power	2019	32	NA	Qualifying Facility (QF)	Biomass	Wendel	CA
12H007	Sts Hydropower (Kanaka)	STS Hydropower Ltd. (Kanaka)	2019	1.1	NA	Qualifying Facility (QF)	Hydro: Small	Oroville	CA
13H024	Olsen Power Partners	Olsen Power Partners	2019	5	NA	Qualifying Facility (QF)	Hydro: Small	Whitmore	CA
15H005	Eif Haypress LLC (LWR)	Haypress Hydroelectric, Inc. (LWR)	2019	6.1	NA	Qualifying Facility (QF)	Hydro: Small	Sierra City	CA
15H006	Eif Haypress LLC (Mdl)	Haypress Hydroelectric, Inc. (MDL)	2019	8.7	NA	Qualifying Facility (QF)	Hydro: Small	Sierra City	CA
25H037	Friant Power Authority	Friant Power Authority	2019	25	NA	Qualifying Facility (QF)	Hydro: Small	Friant	CA
25H073	Olcese Water District	Kern Hydro (Olcese)	2019	16	NA	Qualifying Facility (QF)	Hydro: Small	Bakersfield	CA
25P026	Rio Bravo Fresno	Rio Bravo Fresno	2019	26.5	NA	Qualifying Facility (QF)	Biomass	Fresno	CA
33R054	Klondike IIIA	Klondike IIIA Wind Power	2019	90	263.258	RPS	Wind	Wasco	OR
33R061AB	Castelanelli Bros. Biogas	Castelanelli Bros.	2019	0.3	1.3	AB1969/FiT	Biogas Generation	Lodi	CA
33R101AB	Snow Mountain Hydro (Lost Creek 1) – Contract	Lost Creek 1	2019	1.1	9.636	AB1969/FiT	Hydro: Small	Hat Creek	CA
33R102AB	Snow Mountain Hydro (Lost Creek 2) – Contract	Lost Creek 2	2019	0.5	4.38	AB1969/FiT	Hydro: Small	Hat Creek	CA
12H010	Deadwood Creek (Hydro Sierra Energy, LLC)	Deadwood Creek (Yuba County Water Agency)	2020	2	NA	Qualifying Facility (QF)	Hydro: Small	Challenge	CA
13H013	Snow Mountain Hydro LLC (Cove)	Snow Mountain Hydro (Cove)	2020	5	NA	Qualifying Facility (QF)	Hydro: Small	Montgomery Creek	CA
13H016	Snow Mountain Hydro LLC (Burney Creek)	Burney Creek – Amendment	2020	3	NA	Qualifying Facility (QF)	Hydro: Small	Burney	CA
13H035	Snow Mountain Hydro LLC (Ponderosa Bailey Creek)	Snow Mountain Hydro (Ponderosa Bailey Creek)	2020	1.1	NA	Qualifying Facility (QF)	Hydro: Small	Manton	CA
15P028	Rio Bravo Rocklin	Rocklin Facility	2020	25	NA	Qualifying Facility (QF)	Biomass	Rocklin	CA
16P054	Thermal Energy Dev. Corp.	Thermal Energy Dev. Corp.	2020	21	NA	Qualifying Facility (QF)	Biomass	Tracy	CA
25H149	Orange Cove Irrigation Dist.	Orange Cove Irrigation Dist.	2020	0.45	NA	Qualifying Facility (QF)	Hydro: Small	Friant	CA
25H150	Kings River Hydro Co.	Kings River Hydro Co.	2020	1	NA	Qualifying Facility (QF)	Hydro: Small	Sanger	CA
33R074	SFWP (RPS) – Sly Creek / Kelly Ridge	Multiple	2020	23	106	RPS	Hydro: Small	Multiple	Multiple
33R075	Woodland Biomass	Woodland Biomass	2020	25	175	RPS	Biomass	Woodland	CA
33R096AB	Combie South FiT	Combie South Powerhouse	2020	1.5	3.947	AB1969/FiT	Hydro: Small	Grass Valley	CA
33R141AB	NID Scotts Flat FiT	Scotts Flat Powerhouse	2020	0.85	3.203	AB1969/FiT	Hydro: Small	Nevada City	CA
33R146AB	Blake's Landing – 80kW Generator	80kW Generator	2020	0.08	0.6	AB1969/FiT	Biogas Generation	Marshall	CA
33R015	Shiloh I Wind Project	Shiloh I Wind	2021	75	225	RPS	Wind	Birds Landing	CA
33R093	Geysers – 2010 – 50/250/425 MW	Multiple	2021	250	2080	RPS	Geothermal	Multiple	Multiple
33R140	El Dorado Irrigation District	Multiple	2021	22	99.3	RPS	Hydro: Small	Multiple	Multiple
33R030	Klondike III	Klondike III Wind Power	2022	85	265	RPS	Wind	Wasco	OR
33R230AB	Wolfsen Bypass FiT	Wolfsen Bypass	2022	0.98	5	AB1969/FiT	Hydro: Small	Los Banos	CA
33R231AB	San Luis Bypass FiT	San Luis Bypass	2022	0.6	3	AB1969/FiT	Hydro: Small	Los Banos	CA
33R240AB	South Sutter Water FiT	Vanjop No. 1	2022	0.395	2	AB1969/FiT	Hydro: Small	Sheridan	CA
33R246	Wind Resource I – RAM 1	Wind Resource I	2022	8.71	15.41	RPS	Wind	Tehachapi	CA
33R250AB	Browns Valley Irrigation District FiT	Virginia Ranch Dam Powerhouse	2022	1.04	5.2	AB1969/FiT	Hydro: Small	Oregon House	CA
08C078	City Of Watsonville	City Of Watsonville	2023	0.55	NA	Qualifying Facility (QF)	Biogas Generation	Watsonville	CA
33R276	Wind Resource II – RAM 2	Wind Resource II (1)	2023	19.955	46.41	RPS	Wind	Tehachapi	CA
33R284	ABEC Bidart-Stockdale LLC	Bidart Dairy III (Stockdale)	2023	0.6	1.4	RPS	Biogas Generation	Bakersfield	CA
33R045	Rattlesnake Road Wind Power Project	Arlington Wind Power Project – Rattlesnake Road	2024	102.9	240	RPS	Wind	Arlington	OR
33R077AB	Combie North FiT	Combie North Powerhouse	2024	0.5	1.316	AB1969/FiT	Hydro: Small	Grass Valley	CA
33R333RM	Digger Creek Hydro	Digger Creek Hydro	2024	0.65	3.5	AB1969/FiT	Hydro: Small	Manton	CA
33R337RM	Clover Flat LFG	Clover Flat LFG	2024	0.848	5.747	AB1969/FiT	Biogas Generation	Calistoga	CA
33R053AB	Santa Maria II	Santa Maria II LFG Power Plant	2025	1.42	12.439	AB1969/FiT	Biogas Generation	Santa Maria	CA
33R058	Hatchet Ridge	Hatchet Ridge Wind	2025	103.2	303	RPS	Wind	Burney	CA
33R083	Vantage Wind Energy Center	Vantage Wind Energy Center	2025	90	277	RPS	Wind	Ellensburg	WA
33R342RM	Water Wheel Ranch	Water Wheel Ranch (SB32)	2025	0.975	3.4	AB1969/FiT	Hydro: Small	Round Mountain	CA

This Expiring Contract List does not include any projects that are non-operational

APPENDICES F.1 – F.5b

Redacted in Entirety

January 14, 2016

APPENDIX G

Other Modeling Assumptions Informing Quantitative Calculation

January 14, 2016

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Other Modeling Assumptions Informing Quantitative Calculation[1]

<table>
<tr><th colspan="2">Assumptions Related to Procurement Quantity Requirement</th></tr>
<tr><td>Compliance Periods</td><td>

As implemented by D.11-12-020, SB 2 1X requires retail sellers of electricity to meet the following RPS procurement quantity requirements beginning on January 1, 2011:

An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).
Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
33 percent of bundled retail sales in 2021 and all years thereafter.

Under the 40 percent scenario, requirements that are consistent with the following formula: (.33 * 2021 retail sales) + (.37 * 2022 retail sales) + (.37 * 2023 retail sales) + (.40 * 2024 retail sales) and beyond.

</td></tr>
<tr><th colspan="2">Assumptions Related to Forecasted Generation</th></tr>
<tr><td>Non-QF Projects

Contracts Executed Post-2002</td><td>

Except for the “OFF/Closely Watched” contract category (see Section 4), all non-QF signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract.

</td></tr>
<tr><td>QF Non-Hydro Projects

Contracts Executed Pre-2002</td><td>

Forecast is typically based on an average of the three most recent calendar year deliveries.
Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.

</td></tr>
</table>

1 All assumptions in this table reflect an April 30, 2015 data vintage which is consistent with the data vintage of Appendices C1 – C4.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

<table>
<tr><td>QF Hydro

Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets</td><td>

Forecast is typically based on historical production, calendar year deliveries, and regularly updated with PG&E’s latest internal hydro updates.
Projects are forecasted at 48% of average water year generation for 2015 (based on PG&E’s April 30, 2015 vintage internal hydro delivery forecast) and reverting to average water years in later years.
Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
</td></tr>
<tr><td>Non-QF Hydro

Utility Owned Generation (UOG) and Irrigation District Water Authority (IDWA)</td><td>

Forecasts reflect PG&E’s best available projections for hydro conditions.
Projects are forecasted at 48% of average water year generation for 2015 (based on PG&E’s April 30, 2015 vintage internal hydro delivery forecast) and reverting to average water years in later years.
Year 2015 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
</td></tr>
<tr><td>Future Volumes from Pre-Approved Programs</td><td>
Feed-in Tariffs

E-SRG, E-PWF (AB 1969 FIT)

All deliveries from executed contracts are assumed at 100% of contract volumes.
Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date.

ReMAT

All deliveries from executed contracts are assumed at 100% of contract volumes.
Modeled start date for generic volumes assumed to begin 7/1/2016 and ramp up linearly until 1/1/2019, reaching a total of ~114 MW.

SB1122 (Bioenergy Feed-in Tariff Program)

Modeled start date for generic volumes assumed to begin 7/1/2017 and ramp up linearly until 7/1/2021, reaching a total of ~111 MW.

Renewable Auction Mechanism (Remaining Capacity)

For planning purposes PG&E assumed a project start date equal to 12/1/2017.
Technology mix assumed to be 32 MW of as-available peaking.
</td></tr>
</table>

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

	• All deliveries from executed contracts are assumed at 100% of contract volumes. **PV Originally Authorized for PG&E Photovoltaic Program** • Consistent with PG&E's February 26, 2014 Petition for Modification (PFM)[2] requesting to terminate the PV Program and modify the RAM Decision process to procure the remaining PV Program volumes using RAM solicitation processes PG&E assumed that the Renewable Auction Mechanism accommodates the remaining 200 MW of PG&E's PV Program volumes. • For planning purposes, PG&E has assumed that a total of 209 MW will be coming online between 2017 and 2018.[3] • All deliveries from executed contracts are assumed at 100% of contract volumes.
Re-contracting	• For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained: 1. PG&E does not yet have contractual commitments for these expiring volumes; 2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life; 3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and 4. Assuming re-contracted volumes obscures PG&E's current real need for additional energy in later years. • Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources. • This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E's Annual RPS compliance filing that only shows PG&E's current contractual commitments.
Shortlisted Projects *From 2014 Solicitation or Bilateral Offer*	• No shortlisted projects are included in PG&E's forecast. • Only executed contracts, or generic deliveries from pre-approved procurement programs (i.e., RAM, Feed-in Tariffs, etc.) are included in PG&E's forecast.

2 Advice Letter 3809-E. http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RAM/ELEC_3809-E.pdf.

3 This assumption is based on a modeling vintage of April 2015.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Green Tariff Shared Renewables (GTSR)	• If the Commission approves PG&E's pending advice letters to implement GTSR Program, PG&E plans to allocate small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs. • Once the GTSR program is underway, PG&E would also incorporate any GTSR related impacts on its RPS compliance position into future updates to its RNS.
Banking	• PG&E assumes that (1) Category 3 products that do not exceed applicable portfolio content limits are not deducted from bankable volumes, (2) grandfathered (pre-June 1, 2010) short-term products are bankable, and (3) that banked volumes may be applied in any period onward. • PG&E's accounting is consistent with the direction set forth in Decision 12-06-038.
RPS Sales	• PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's renewable net short (RNS), future RPS cost projections and assessment of the current REC market does not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E will update its RNS if it executes any such agreements.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

<table>
<tr><th colspan="2">Assumptions Related to Forecasted Sales</th></tr>
<tr><td>Bundled Retail Sales
RNS (App. C1 and C3)</td><td>• Forecasts of retail sales for the first five years of the forecast were generated by PG&E’s Load Forecasting and Research team in April 2015, and may be updated throughout the year as additional data becomes available.
• Forecasts of retail sales beyond the first five years are sourced from the latest LTPP standardized planning assumptions, per the May 21, 2014 ALJ Ruling in R.11-05-005 regarding the methodology for calculating the renewable net short.
• Monthly recorded sales replace forecasts as 2015 progresses.</td></tr>
<tr><td>Bundled Retail Sales

Alternate RNS
(App. C2 and C4)</td><td>• Forecasts of retail sales were generated by PG&E’s Load Forecasting and Research team in April 2015, and may be updated throughout the year as additional data becomes available.
• Monthly recorded sales replace forecasts as 2015 progresses.</td></tr>
</table>

APPENDIX H

Responses to Renewable Net Short Questions

January 14, 2016

Appendix H - Responses to Renewable Net Short Questions

The following presents PG&E's responses to questions set forth in the May 21, 2014 *Administrative Law Judge's Ruling on Renewable Net Short*.

RPS Compliance Risk

1. How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?

PG&E considers historical performance of online resources in both of its models. First, it considers this performance in developing the generation forecast in its deterministic model. As discussed in Appendix G, future projections of RPS deliveries in the deterministic model are based on a blended three year average output for QF contracts.

In addition, within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type. A probabilistic distribution is built for each resource based on its calculated coefficient of variation. This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model. Section 6.2.2 of the RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

2. Do you anticipate any future changes to the current bundled retail sales forecast? If so, describe how the anticipated changes impact the RNS.

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, DA and CCA participation levels, and distributed generation. PG&E's most recent Sales Forecast used in the RPS Plan is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan submitted in October 2014 in Rulemaking 13-12-010. It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur. PG&E updates the bundled load forecasts annually to reflect any new events and capture actual load changes. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts. Changes in retail sales tend to be variable and persistent, [redacted], particularly over time. However, PG&E's modeling results presented in Section 7 are robust to future changes in sales.

3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?

To the extent that RPS projects are economically bid and do not clear the market, or are curtailed for system reliability, PG&E expects that curtailment will impact its RNS. As described in Sections 6.2.3 and 11, the stochastic model evaluates uncertainty associated with RPS generation variability, including assumptions of future levels of RPS curtailment.

4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?

PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of approximately 99% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, and 87% in PG&E's 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry. While PG&E has continued to see a general trend towards higher project success rates, its revised success rate assumption (from 87% to 99%) reflects the recent removal of several projects from PG&E's portfolio due to contract termination and an update to the "Closely Watched" category described in Section 6.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically-optimized net short (SONS). See the answer to question #5 below for details on these new assumptions.

5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, as described in Section 6.1.2, PG&E may categorize projects experiencing considerable development challenges as "Closely Watched" and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the "Closely Watched" category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in Section 6.2.4. To model the project

failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted].
For example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Appendices F.2a and F.2b show PG&E's simulated failure rate and for the period 2015-2030 in the 33% RPS and 40% RPS, respectively.

SUMMARY:
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Reference Above and Uncertainty it Represents	Deterministic Model	Stochastic Model
Question #2: Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years.	Distribution based on most recent (2015) PG&E bundled retail sales forecast.
Question #4 and #5: Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate.
Question #1: RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
Question #3: Curtailment[1]	None	33% Scenario: [redacted] of RPS requirement 40% Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond.

1 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information.

6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.

As described in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. Under a 40% by 2024 scenario and current market assumptions, PG&E would plan to maintain a minimum Bank level of at least [redacted] GWh. However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section 6 for additional information.

7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.

As described in Sections 6 and 7, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted], projecting that PG&E's forecasted Bank size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use RECs above the PQR, as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

PG&E's optimization strategy includes consideration of sales of surplus procurement. Consistent with the Commission-approved RNS, PG&E's physical net short and cost projections do not include any future projected sales of bankable contracted deliveries. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable RPS volumes if it can still maintain adequate Bank and if market conditions are favorable. As PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted].

VMOP

8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.

As discussed in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. [redacted], PG&E believes it would be imprudent to use its entire projected Bank toward meeting the 33% RPS target or 40% RPS scenario, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% target, and will thus reduce long-term costs of the RPS Program.

9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.

As discussed in Sections 6 and 7, PG&E's stochastic model optimizes its results to inform its RPS procurement strategy, which includes using a portion of the Bank as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. The model suggests a specific level of procurement and resulting Bank usage for each year. PG&E then uses these model results as a tool to guide its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

Cost-Effectiveness

10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?

As discussed in greater detail in Sections 6, 7, and 8 of this Plan, [redacted]. As long as PG&E can continue to maintain an adequate Bank that does not jeopardize PG&E's ability to manage its non-compliance risk and thus avoid being caught in a "seller's market," where PG&E would face potentially high market prices in order to meet near-term compliance deadlines.

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time.

11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?

PG&E's current RPS portfolio consists of primarily Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the existing restrictions on banking of excess procurement limit PG&E's ability to fully optimize its portfolio. Under the current RPS rules, short-term contracts cannot count towards excess procurement eligible for banking toward a future RPS compliance period. The result is that any entity that has excess procurement during a particular compliance period is effectively restricted from procuring short-term contracts during that compliance period. Only when an entity does not exceed its compliance period target, is it able to count short-term procurement towards meeting its targets.

PG&E currently maintains a bank in order to help mitigate procurement and load variability. Thus, the inability for short-term contracts to contribute to the bank restricts our mitigation strategy. Allowing the unrestricted banking of all RPS products, including those associated with short-term contracts, would enable PG&E to better manage risks and achieve cost-savings for our customers.

ATTACHMENT B

Redline version of the Public 2015 RPS Plan

APPENDIX A

Redline Showing Changes in ~~August 4, 2015 Draft~~ January 14, 2016 Final 2015 RPS Plan Compared to ~~December 23, 2014 Final (Revision 1)~~ August 4, 2015 Draft RPS Plan

(Excluding Appendices)

~~August 4, 2015~~

January 14, 2016

Public

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

FINAL 2015 RENEWABLE ENERGY PROCUREMENT PLAN ~~(DRAFT VERSION)~~

~~AUGUST 4, 2015~~
JANUARY 14, 2016

Public

TABLE OF CONTENTS

TABLE OF CONTENTS

(CONTINUED)

TABLE OF CONTENTS

(CONTINUED)

LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its Final 2015 Renewables Portfolio Standard ("RPS") Plan ("2015 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the ~~Assigned Commissioner~~Commission in ~~this proceeding in the *Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewable Portfolio Standard Procurement Plans* ("ACR") issued on May 28, 2015~~Decision ("D.") 15-12-025. PG&E's 2015 RPS Plan includes a summary of key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the ~~ACR.[1] PG&E believes its 2015 RPS Plan satisfies all of the statutory and Commission requirements and addresses key policy issues that have arisen as the renewable energy industry matures and grows in California.~~*Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewable Portfolio Standard Procurement Plans* ("ACR") issued in this proceeding on May 28, 2015.[2]

1 Summary of Key Issues

1.1 PG&E's RPS Position

PG&E projects that under both the current 33% RPS by 2020 target, as well as a 40% by 2024 scenario, it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods and will not have incremental procurement need until at least 2022. Under the current 33% RPS target, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying banked volumes of excess procurement ("Bank") beginning in [redacted]. Under the 40% RPS by 2024 scenario, PG&E projects that it will have incremental procurement need beginning in [redacted], after applying Bank beginning in [redacted]. In both situations, PG&E anticipates additional steady, incremental long-term procurement in

~~1 *See* ACR, pp. 8-20.~~

2 *See* ACR, pp. 8-20.

subsequent years to avoid the need to procure large volumes in any single year to meet compliance needs and maintain minimum Bank levels.

1.2 PG&E ~~Proposes~~Will Not ~~to~~ Hold a Request for Offers in 2015

Given its current RPS compliance position, PG&E ~~proposes~~will not ~~to~~ hold an RPS solicitation in 2015. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future solicitations in next year's RPS Plan. Although many factors could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs in 2016.[3] PG&E will seek permission from the Commission to procure any amounts other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff ("FIT") and RAM) during the time period covered by the 2015 solicitation cycle. In 2016, PG&E will reassess its Renewable Net Short ("RNS") position and determine its updated procurement needs. PG&E's ~~proposal~~decision to not ~~to~~ hold a 2015 RPS solicitation is consistent with a proposal made by San Diego Gas & Electric Company ("SDG&E") in its 2014 RPS Plan, and approved by the Commission given SDG&E's lack of need.[4]

1.3 Consideration of Higher RPS Targets Should Be Integrated With Broader State Greenhouse Gas Goals

California's RPS has played, and will continue to play, an important role in lowering electric sector greenhouse gas ("GHG") emissions and meeting the state's clean energy goals. PG&E supports maintaining the existing requirements that load-

---

3 Mandated programs include Renewable Auction Mechanism ("RAM"), Renewable Market Adjusting Tariff ("ReMAT"), and Bioenergy Market Adjusting Tariff ("BioMAT"). In addition, while not pursuant to the RPS mandate, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program~~ ("GTSR").~~.

4 ~~Decision ("~~D~~.")~~.14-11-032, p. 32, Ordering Paragraph~~ ("OP")~~ 17.

serving entities ("LSE") provide a minimum of 33% RPS in 2020~~ and beyond. As the state looks beyond 2020, however~~, moving towards 50% in 2030. However, PG&E believes California's clean energy policy should be centered on achieving the most cost-effective GHG reductions needed to meet the Governor's 2030 goal of emissions that are 40% ~~of~~below 1990 levels.[5]

Before taking any action that would increase the RPS requirements, the Commission should consider how the RPS program fits within a comprehensive GHG policy framework built to achieve emissions reductions through a combination of actions, as opposed to potentially inefficient carve-out mechanisms.[6] Renewable energy policy should be more completely aligned with this broader policy context in order to ensure that GHG reduction targets are achieved in an integrated and economically efficient manner. Rather than reflexively raise the RPS targets, the CPUC should adopt a strategy focused on flexibility, equitable rules for all LSEs, affordability, and market and system stability.[7]

1.4 Renewable Portfolio Growth Increases Customer Rate Impacts

As a part of this RPS Plan, PG&E is providing historic and forecasted RPS cost and rate information. From 2003-2015, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. The costs of the RPS Program have already and will continue to impact customer bills. From 2003-2016, PG&E estimates its annual rate impact from RPS procurement has increased from 0.7 cents per

---

5 Office of California Governor Edmund G. Brown, Executive Order 4-29-2015 (available at http://gov.ca.gov/news.php?id=18938).

6 For further discussion of the cost impacts of mandated procurement programs, see Section 13.3.

7 For further discussion, see PG&E's opening and reply comments in response to *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program (R.15-02-020)* filed on March 26, 2015 and April 6, 2015, respectively.

kilowatt-hour ("¢/kWh") in 2003 to an estimated 3.5¢/kWh in 2016.[8] The growth in rates due to RPS procurement costs will continue to increase through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh, or approximately $2.3 billion. Further detail regarding RPS costs is provided in Section 13 and the annual rate impact of forecasted procurement is detailed in Table 2 of Appendix D.

To address these rate impacts, PG&E's procurement strategy attempts to minimize cost and maximize value to customers, while satisfying the RPS program requirements. To accomplish this goal, PG&E promotes competitive processes to procure incremental RPS volumes, strategically uses its Bank, and avoids long-term over-procurement.

As described above, a more integrated GHG policy framework that enables LSEs to adapt to changing needs, costs, and circumstances and manage the integration of variable resources would provide additional opportunities to lower customer costs. New technologies will emerge and the mix and cost-effectiveness of GHG emissions reduction strategies will undoubtedly evolve over the next several years. PG&E believes that a more flexible implementation of the RPS Program that allows LSEs to optimize a portfolio of different GHG reduction strategies would facilitate meeting the State's environmental goals at the lowest possible costs and best portfolio fit, and provide the maximum benefits to customers. Similarly, as discussed in Section 13.3, mandated procurement programs within the RPS reduce the program's efficiency while increasing costs.

1.5 PG&E's Bank Is Necessary to Ensure Long-Term Compliance

PG&E views its Bank as necessary to: (1) mitigate risks associated with variability in load; (2) protect against project failure or delay exceeding forecasts; and

---

8 "Annual Rate Impact" should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

(3) avoid intentional over-procurement above the 33% RPS target by managing year-to-year generation variability from performing RPS resources. The Bank allows PG&E to mitigate the need to procure additional RPS products at potentially high market prices in order to meet near-term compliance deadlines. With an adequate Bank, PG&E aims to minimize customer cost by having the flexibility not to procure in "seller's market" situations. More information on forecasted Bank size and minimum Bank levels under both 33% and 40% RPS is provided in Section 7 below.

PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's RNS, future RPS cost projections, and assessment of the current Renewable Energy Credit ("REC") market do not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

1.6 RPS Rules Should Be Applied Consistently and Equitably Across All LSEs

PG&E's long-term position is a forecast based on a number of assumptions, including a certain amount of load departure due to Community Choice Aggregation ("CCA") and distributed generation growth. While it is possible that this forecasted load departure may not fully materialize or occur at the rate assumed in the forecast, PG&E's forecast is a reasonable scenario based on current trends. Under the existing percentage-based RPS targets, any departure of PG&E's load to CCAs naturally results in both a reduction of PG&E's required RPS procurement quantities and a corresponding increase in RPS procurement by CCAs. Thus, CCAs will be required to shoulder an increasing portion of the State's RPS procurement goals. The consistent and equitable application of all RPS rules and requirements to all Commission-jurisdictional LSEs, including CCAs and ~~Electric~~Energy Service Providers ("ESPs"), will help to ensure that all LSEs are helping California achieve its ambitious renewable energy goals.

2 Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E’s portfolio forecast and procurement decisions are influenced by ongoing legislative and regulatory changes to the RPS Program. The following is a description of recent changes to the RPS Program that have impacted PG&E’s RPS procurement.

2.1 Commission Implementation of Senate Bill 2 (1x)

Senate Bill (“SB”) 2 (1x), enacted in April 2011 and effective as of December 11, 2011, made significant changes to the RPS Program, most notably extending the RPS goal from 20% of retail sales of all California investor-owned utilities (“IOUs”), ESPs, publicly~~-~~ owned utilities~~ (“POUs”),~~, and CCAs by the end of 2010, to a goal of 33% of retail sales by 2020. The Commission issued an Order Instituting Rulemaking to implement SB 2 (1x) in May 2011 and has subsequently issued a number of key decisions implementing certain “high priority” issues needed to implement the complex provisions of SB 2~~-~~ (1x). In February 2015, the Commission opened a new ~~rulemaking~~Rulemaking (R.) 15-02-020 to address remaining issues from this earlier proceeding, as well as other elements of the ongoing administration of the RPS Program. Commission action on remaining and new key issues may impact PG&E’s procurement need and actions going forward, notwithstanding the forecasts and projections included in this Plan.

Key Commission decisions issued to date implementing SB 2 (1x) include D.11-12-052 which defined portfolio content categories (“PCC”), D.11-12-020 which outlined compliance period targets for the 33% RPS target, and D.12-06-038 which implemented changes to the RPS compliance rules for retail sellers, including treatment of prior procurement to meet RPS obligations for both the 20% and 33% RPS Programs. D.12-06-038 also adopted rules on calculating the RPS Bank, meeting the portfolio balance requirements, and for reporting annually to the Commission on RPS procurement. Finally, on December 4, 2014, the CPUC adopted D.14-12-023 setting RPS compliance and enforcement rules under SB 2 (1X).

2.2 Cost Containment

When California's legislature passed SB 2 (1x), it required the CPUC to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS target from causing "disproportionate rate impacts." If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only "de minimis" rate impacts.

PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E strongly supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. PG&E urges the Commission to finalize the PEL as soon as possible~~, given that the RPS statute requires the Commission to report by January 1, 2016 on the status of each IOU in achieving 33% RPS within the adopted PEL, and to propose any necessary modifications to the PEL~~.

2.3 Implementation of Bioenergy Legislation

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ("MW") in total of new small-scale bioenergy projects 3 MW or less through the ~~Feed-In Tariff (~~"FIT"~~)~~ Program. The total IOU program MWs are allocated into three~~-~~ technology categories: 110 MW for biogas from wastewater plants and green waste; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. The allocation of MWs by project type for each IOU, as well as the program design, is being determined by the Commission in proceedings currently underway. PG&E has worked with the Commission and stakeholders in order to ensure that the SB 1122 program is implemented in a way that balances the needs of the bioenergy industry with clear cost containment mechanisms that protect customers from excessive costs. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 program ("BioMAT") began accepting participants on December 1, 2015 and the first program period will start on February 1, 2016.

2.4 Senate Bill 350

On October 7, 2015, Governor Brown signed SB 350 (de Leon), known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increases the RPS target from 33% in 2020 to 50% in 2030. The Commission will begin implementation of SB 350 in 2016.

3 Assessment of RPS Portfolio Supplies and Demand

3.1 Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's 33% RPS target. PG&E is currently required to procure the following quantities of RPS-eligible products:

- 2011-2013 (First Compliance Period): 20% of the combined bundled retail sales.
- 2014-2016 (Second Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).

- 2021 and beyond: 33% of combined retail sales in 2021 ~~and each year thereafter.~~.[9]

Based on preliminary results presented in Appendix C.2a, PG&E delivered 27.0% of its power from RPS-eligible renewable sources in 2014.

As described more fully in Section 7 and reported in the current RNS calculations in Appendix C.2a, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. Under the ~~current~~ 33% RPS target, PG&E projects that it will not have incremental procurement need until at least 2022, with need beginning in [redacted], after applying Bank beginning in [redacted].

Under a 40% RPS scenario, PG&E modeled the same trajectory through 2020 as described above, but modeled the following RPS requirements starting in 2021:

- 33% of combined bundled retail sales in 2021;
- 37% of combined bundled retail sales in 2022;
- 37% of combined bundled retail sales in 2023; and
- 40% of combined bundled retail sales in 2024 and each year thereafter.

For this scenario, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E projects that it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. PG&E projects that it will have incremental procurement need beginning in [redacted], after applying its Bank towards its physical net short beginning in [redacted].[10]

---

9 SB 350 establishes the following new multi-year RPS compliance period: 40% by the end of 2021-2024; 45% by the end of 2025-2027; and 50% by the end of 2028-2030 and each year thereafter.

10 This projection includes future volumes from mandated programs, such as the RAM and FIT Programs.

3.2 Supply

3.2.1 Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes over 8,000 MW of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar photovoltaic ("PV"), biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 6 and 7.

As described in further detail in Section 7.1, for the 2015 RPS Plan, PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of approximately 99% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, and 87% in PG&E's 2014 RPS Plan. This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations. While PG&E has continued to see a general trend towards higher project success rates, the change in its success rate assumption from 2014 to 2015 (from 87% to 99%) reflects the recent removal of several projects from PG&E's portfolio due to contract terminations and an update to the "Closely Watched" category described in Section 6.

Consistent with the project trends reported in its 2014 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have continued to increase many projects' cost-effectiveness, contributing to their eventual completion. Progress in the siting and permitting of projects has also supported PG&E's sustained high success rate. As described in more detail in

Section 3, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in Sections 5 and 6.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 6, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted,[11] although these resources are encouraged to bid into PG&E's future competitive solicitations.

3.2.2 Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission adopted D.15-01-051 implementing a GTSR framework, approving the IOUs' applications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.

Pursuant to D.15-01-051, PG&E has submitted several advice letters related to implementation of the GTSR program that are currently pending before the Commission. In February, PG&E filed an advice letter containing its plans for advance procurement for the GTSR Program and identifying the eligible census tracts for environmental justice projects in its service territories.[12] In May, together with Southern

---

[11] Although the physical net short calculations in PG&E's deterministic model do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive. PG&E's deterministic and stochastic models are described in more detail below in Section 6.

[12] PG&E Advice Letter 4593-E (supplemented March 25, 2015).

California Edison Company ~~(SCE)~~ and ~~San Diego Gas & Electric Company (~~SDG&E~~),~~, PG&E submitted a Joint Procurement Implementation Advice Letter ~~(JPIAL),~~, addressing each utility's plans for ongoing GTSR Program procurement and RPS resource and ~~renewable energy credit (~~REC~~)~~ separation and tracking.[13] Concurrently, PG&E filed a Marketing Implementation Advice Letter ~~(MIAL)~~[14] and a Customer-Side Implementation Advice Letter ~~(CSIAL)~~[15] with details regarding implementation. In addition, to accommodate GTSR procurement, PG&E filed Advice Letter ~~-~~ 4605-E to change its RAM 6 ~~PPAs~~Power Purchase Agreements ("PPA") and Request for Offer ("RFO") instructions, consistent with the minimum goals for 2015 identified in D.15-01-051.[16]

The GTSR program will impact PG&E's RPS position in two ~~-~~ ways: (1) PG&E's RPS supply may be affected; and (2) PG&E's retail sales will be reduced corresponding to program participation. The GTSR decision permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. PG&E will implement tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff programs. Because the GTSR implementation Advice Letters discussed above[17] have not yet been approved, PG&E's RNS calculation submitted with this RPS Plan does not reflect the

---

[13] Advice Letter 4637-E.

[14] Advice Letter 4638-E.

[15] Advice Letter 4639-E.

[16] *See* D.15-01-051, Section 4.2.4, pp. 25-28.

[17] Advice Letters 4637-E, 4638-E and 4639-E.

impact of GTSR on PG&E's RPS position. Due to the relatively small volumes of the GTSR interim pool compared to PG&E's overall RNS position, PG&E believes that its forecasts of meeting the second and third compliance period RPS targets as well as its incremental need year under either a 33% or 40% RPS would remain the same once these small GTSR volumes are incorporated. PG&E will update future RNS calculations to reflect GTSR program impacts after the advice letters implementing the program are approved.

3.2.3 RPS Market Trends and Lessons Learned

As PG&E's renewable portfolio has expanded to meet the RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the three key goals of: (1) reaching, and sustaining, the 33% RPS target; (2) minimizing customer cost within an acceptable level of risk; and (3) ensuring it maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty. However, PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as solar PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend driven by growth of renewable resources in the California Independent System Operator ("CAISO") system is the downward movement of mid-day market prices. Many renewable energy project types have little to no variable costs and therefore additions tend to move market clearing prices down the dispatch stack. This has led to a change in the energy values associated with RPS offers, with decreasing value of renewable projects that generate during mid-day hours.

The growth of renewable resources has also produced operational challenges, such as overgeneration situations and negative market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address overgeneration and negative pricing situations that are likely to increase in frequency in the future. These provisions have both operational and customer benefits. From an operational perspective, this flexibility allows PG&E to offer its RPS-eligible resources into the CAISO's economic dispatch, which can reduce the potential for overgeneration conditions and facilitate reliable operation of the electrical grid. In addition, economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 11.

3.3 Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Compliance rules for the RPS Program were established in D.12-06-038. In addition, the Commission issued D.11-12-052, to define three statutory PCCs of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 6; in particular, uncertainty around bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

3.3.1 Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need through [redacted] under a 33% RPS requirement and through [redacted] under a 40% RPS scenario, PG&E ~~proposes to~~plans not to hold an RPS solicitation in 2015. As discussed in the summary of key issues, PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future RFOs in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to procure additional volumes of incremental RPS-eligible contracts in 2016 through mandated procurement programs, such as the RAM, ReMAT, and BioMAT Programs. PG&E will seek permission from the Commission to procure any amounts other than amounts separately mandated by the Commission (*i.e.*, FIT and RAM) during the time period covered by the 2015 solicitation cycle.

3.3.2 Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. PG&E's most recent Load Forecast, which is used in this RPS Plan, is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan ("BPP") submitted in October 2014 in R.13-12-010. PG&E updates the bundled load forecasts annually to reflect any new events and to capture actual load changes. It is important to emphasize that PG&E's Alternative Scenario is a forecast that includes a number of assumptions regarding events which may or may not occur.

PG&E is currently projecting a decrease in retail sales in 2015 and a continued retail sales decrease through 2024, followed by modest growth thereafter. These changes are driven by the increasing impacts of Energy Efficiency ~~("EE"),~~, customer-sited generation, and Direct Access ("DA") and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 6, 7, and 8, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for its risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 6 and 7.

3.4 Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs such as the RAM, ReMAT, and BioMAT Programs, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting in the 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value ("NMV") methodology will be updated to use the values and methodologies of the final integration cost adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[18]

3.5 RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of

---

[18] *See* PG&E, 2014 RPS Solicitation Protocol, pp. 24-28 (available at http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf).

geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the NMV valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement. PG&E's current quantitative and qualitative approach to resource diversity would remain the same under a 40% RPS scenario as the existing approach described above.

3.6 Optimizing Cost, Value, and Risk for the Ratepayer

From 2003 to 2012, PG&E's annual RPS-eligible procurement and generation costs from its existing contracts and utility-owned portfolio grew at a relatively modest pace. However, the costs of the RPS program are becoming more apparent on customer bills and will increase as RPS projects come online in significant quantities. Over the period of two years (2013 and 2014), the renewable generation in PG&E's portfolio increased by approximately the same amount that it grew over the entire prior history of the RPS Program (2003-2012). In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible, particularly when entering into incremental long-term commitments. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement; and (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to help limit long-term over-procurement. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13.3, as PG&E makes progress toward achieving the 33% RPS target, it expects that the cost impacts of mandated procurement programs that focus on particular technologies or project size may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process, in which all technologies can compete to offer the best value to customers at the lowest cost.

3.7 Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2020 and to minimize customer cost within an acceptable level of risk. PG&E's optimization strategy continues to evolve as its RPS compliance position through 2020 and beyond continues to improve. Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (post-2020). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to manage a 33% RPS operating portfolio after 2020. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 6 and 7.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement; (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E ~~proposes~~will not ~~to~~ hold a 2015 RPS solicitation, future incremental procurement to avoid the need to procure extremely large volumes in any single year remains a central component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes consideration of sales of surplus procurement that provide a value to customers.

The third component of the optimization strategy is effective use of the Bank. Under the existing 33% RPS target and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in [redacted]. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted].

Under a 40% RPS by 2024 scenario, the components of PG&E's optimization strategy would remain the same. However, under the 40% RPS scenario and current market assumptions, PG&E would plan to maintain a minimum Bank size of at least [redacted]. See Section 7 for additional information regarding the use and size of PG&E's Bank.

4 Project Development Status Update

In Appendix B, PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of June 17, 2015.[19] These key project development status indicators help PG&E to determine if a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions.

Within PG&E's active portfolio,[20] there are 107 RPS-eligible projects that were executed after 2002. Seventy-six of these contracts have achieved full commercial operation and started the delivery term under their PPAs. Thirty-one contracts have not started the delivery term under their PPAs. Of the 31 contracts that have not started the delivery term under their PPAs with PG&E: 18 have not yet started construction;

---

19 Appendix B includes PPAs procured through the RAM and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has 72 executed Assembly Bill ~~("AB")~~ 1969 PPAs in its portfolio and 29 ReMAT PPAs, totaling 104 MW of capacity. These small renewable FIT projects are in various stages of development, with 60 already delivering to PG&E under an AB 1969 PPA and 11 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

20 PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and CPUC-approved as of June 17, 2015, not including amended post-2002 QF contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation ("UOG") projects, or FIT projects.

five have started construction but are not yet online; and eight are delivering energy, but have not yet started the delivery term under their PPAs. Based on historic experience, projects that have commenced construction are generally more viable than projects in the pre-construction phase, although PG&E expects most of the pre-construction projects currently in its portfolio to achieve commercial operation under their PPA.

5 Potential Compliance Delays

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E is familiar with the obstacles confronting renewable energy developers. These include securing financing, siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these issues. However, even with these efforts, challenges remain that could ultimately impact PG&E's ability to meet California's RPS goals. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. This section describes the most significant RPS compliance risks and some of the steps PG&E is taking to mitigate them.[21]

5.1 Project Financing

The financing environment for solar PV and wind projects continues to be healthy, with access to low-cost capital and a variety of ownership structures for project developers. However, for renewable technologies that are less proven, less viable, or reflect a higher risk profile, the financing environment is more constrained, with higher costs of capital and fewer participants willing to lend or invest.

21 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

Federal and state incentives such as the PTC and ITC continue to fuel renewable growth in California. In 2015, the Internal Revenue Service extended the applicable dates for the "beginning of construction" guidance for PTC-eligible facilities to January 1, 2015, and the "placed in service" date to January 1, 2017.[22] This allows the PTC or ITC tax benefits for non-solar facilities to continue well beyond 2014. Solar energy facilities continue to be eligible for a 30% ITC if they are placed in service by December 31, 2016.[23] The five-year and seven-year Modified Accelerated Cost Recovery System ("MACRS") allows for accelerated tax depreciation deductions to renewable tangible property.[24] These tax incentives and the MACRS depreciation deductions enable businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for projects to negotiate financing. As a result, tax incentives have spurred significant investment in renewable energy and generally amount to between 35 and 60 cents per dollar ("¢/$") of capital cost.

Tax equity remains a core financing tool for renewable developments, and ownership structures such as Master Limited Partnerships and Yield Cos are also being utilized as project sponsors market and investors competitively shop for solar and wind investments. These structures allow developers who cannot use tax benefits efficiently to barter the benefits to large corporations or investors in exchange for cash infusions for their projects. At this time, tax incentive structures after 2016 are unknown. The

---

22 Notice 2015-~~25~~2025 allows a taxpayer to claim a PTC under Section 45 of the Internal Revenue Code ("IRC"), or a 30% ITC under Section 48 (ITC) in lieu of the PTC, for eligible facilities such as wind, geothermal, biomass, marine, landfill gas, and hydro, if the facility began construction before January 1, 2015 or was placed in service by January~~-~~ 1, 2017.

23 Section 48 of the IRC allows for a tax credit equal to 30% of project's qualifying costs for certain types of commercial energy projects, including solar, geothermal, fuel cells, and small wind projects, and a 10% tax credit for geothermal, micro turbines and combined heat and power. The tax credit is realized in the year that the project is placed in service.

24 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.

PTC and 30% ITC incentives end in 2016. Unless the tax code is modified or extended, the renewable energy ITC will drop to 10% after December 31, 2016. However, there are efforts underway to extend or modify the PTC and ITC.[25] Despite the uncertainty surrounding renewable energy project tax incentives, PG&E believes there are indications that healthy trends for renewable project financing will continue.

5.2 Siting and Permitting

PG&E works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development. For example, PG&E works collaboratively with environmental groups, renewable energy developers and other stakeholders to encourage sound policies through a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the timely development of energy resources in the California desert and other suitable locations. Long-term and comprehensive planning and permitting processes can help better inform and facilitate renewable development.

PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of offers to PG&E's future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects while ensuring environmental integrity.

---

25 H.R. 2412 would extend the renewable energy ITC for a period of five years for eligible renewable solar, small wind energy, fuel cell, micro turbine, thermal energy and combined heat and power system properties that begin construction before January 1, 2022.

In addition, in its proposed budget for fiscal year 2016, the Obama administration proposes to modify and permanently extend the renewable PTC and ITC. For facilities that begin construction in 2016 or later, the proposal would make the PTC permanent and refundable. Solar facilities that qualify for the ITC would be eligible to claim the PTC. The proposal would also permanently extend the ITC at the 30 percent credit level, which is currently scheduled to expire for properties placed in service after December 31, 2016, and it would make permanent the election to claim the ITC in lieu of the PTC for qualified facilities eligible for the PTC.

Permitting challenges for projects are improving as a result of these and other efforts to streamline and adjust the permitting process for renewable energy projects. While these improvement efforts are ongoing, permitting and siting hurdles remain for renewables projects. Common issues may include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected species, and county-imposed moratoriums. These hurdles may impact development schedules for projects.

5.3 Transmission and Interconnection

Achieving timely interconnection is an important part of the project development process. Delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.

Over the past few years, the CAISO and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how these projects would be connecting into the California grid has become increasingly challenging. The growth in these requests has, in turn, extended estimated project development timelines, which creates a significant barrier to financing projects endeavoring to come online within tight contractual milestone dates. Similarly, the growth in interconnection requests has made it difficult to estimate reliable interconnection study results and to identify necessary transmission build-outs.

Accordingly, PG&E has initiated a number of internal efforts and collaborated on external initiatives to address these challenges at both the transmission and distribution levels. Recent notable changes in the distribution-level interconnection process included: (1) amending the Wholesale Distribution Tariff in October 2014 to address modifications similar to those made to the CAISO's Tariff; and (2) amending Rule 21 in January 2015 to capture the technological advances offered by smart inverters.

Additionally, over the past few years, PG&E has worked with the CAISO and industry stakeholders in ongoing stakeholder initiatives enhancing the transmission-level interconnection processes. Most significant among the changes has been the Generator Interconnection and Deliverability Allocation Procedures, which has streamlined the process for identifying customer-funded transmission additions and upgrades under a single comprehensive process. This initiative also provides incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations. PG&E has also actively contributed to the CAISO's Interconnection Process Enhancements stakeholder initiative that seeks to continuously review potential enhancements to the generator interconnection procedures.

Finally, at the intersection of transmission-level and distribution-level interconnections, is the Distributed Generation Deliverability ("DGD") process. In 2013, PG&E collaborated extensively with the CAISO to implement the first annual cycle, and the second and third cycles were successfully completed in 2014 and 2015, respectively. Under the DGD Program, the CAISO conducts an annual study to identify MW amounts of available deliverability at transmission nodes on the CAISO-controlled grid. Based on the deliverability assessment results, distributed generation facilities that are located or seeking interconnection at nodes with identified available deliverability may apply to the appropriate Participating Transmission Owner ("PTO") to receive an assignment of deliverability for Resource Adequacy ("RA") counting purposes.

5.4 Curtailment of RPS Generating Resources

As discussed in more detail in Section 11, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may present an RPS compliance challenge. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 6.2.

5.5 Risk-Adjusted Analysis

PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. As described further in Section 6, deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E's net short calculation.

PG&E's experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. As described in Section 8, PG&E's current expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio, which are captured in PG&E's deterministic model. These deterministic results are time-sensitive and do not account for all of the risks and uncertainties that can cause substantial swings in PG&E's portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 33% RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

6 Risk Assessment

Dynamic risks, such as the factors discussed in Section 5 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales variability and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[26] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as Voluntary Margin of Procurement or VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 6.1 identifies the three risks accounted for in PG&E's deterministic model. Section 6.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 6.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 6.4 notes how the two models help guide PG&E's optimization strategy and

---

26 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

procurement need. Section 7 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices C.2a and C.2b. Section 8 addresses PG&E’s approach to the statutory minimum and voluntary margins of procurement.

6.1 Risks Accounted for in Deterministic Model

PG&E’s deterministic approach models three key risks:

1) **Standard Generation Variability:** the assumed level of deliveries for categories of online RPS projects.

2) **Project Failure:** the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project’s relatively high risk of failure or delay.

3) **Project Delay:** the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E’s portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
DETERMINISTIC MODEL RISKS

RISK	METHODOLOGY	APPLIES TO
Standard Generation Variability	• For non-QF projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled "OFF" (0% deliveries assumption) • All other In Development projects are "ON" (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment~~/~~/Communication with counterparties	Under Construction Projects/ Under Development Projects/ Approved Mandated Programs

6.1.1 Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non-Qualifying Facilities ("QF"); non-hydro QFs; and hydro projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, calendar year deliveries, and regularly updated with PG&E's latest internal hydro updates. The UOG and Irrigation District and Water Agency ("IDWA") forecast is based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix G.

6.1.2 Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0% deliveries) and ON (represented with 100% deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":

   - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.).
   - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data).
   - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization.
   - Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability.
   - Whether a PPA amendment has been executed but has not yet received regulatory approval.
   - Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[27]

2. **ON** – Projects in all other categories are assumed to deliver 100% of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON" projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of "ON" projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of "ON" projects represents executed and future contracts from CPUC-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes with replacement projects within a reasonable timeline.

6.1.3 Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

27 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

6.2 Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E's RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E's portfolio. PG&E's stochastic model assesses the impact of both demand- and-supply-side variables on PG&E's RPS position from the following four categories:

1) **Retail Sales Variability:** This demand-side variable is one of the largest drivers of PG&E's RPS position.
2) **Project Failure Variability:** Considers additional project failure potential beyond the "on-off" approach in the deterministic model.
3) **Curtailment:** Considers buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment.
4) **RPS Generation Variability:** Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year-to-year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
CATEGORIZATION OF IMPACTS ON RPS POSITION

Higher Impact on RPS Position

Impact	Categorization
1. **Retail Sales Variability**: Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** (*If an outcome occurs, the effect persists through more than one year).*
2. **RPS Generation Variability:** Variability in yearly generation is largely an annual phenomenon that has little persistence across time.	**Variable and short-term** (*If an outcome occurs, the effect may only occur for the individual year.)*
3. **Curtailment:** Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
4. **Project Failure Variability:** Lost volume from project failure persists through more than one year.	**Variable and persistent**

Lower Impact on RPS Position

6.2.1 Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, electric vehicles, and distributed generation. However, the variability in load loss due to DA and CCA is not modeled in this same way. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting substantial increases in DA. Load loss due to CCA departure is modeled as an expected value based on an increased forecast of CCA departure. Because forecast errors tend to carry forward into future years, the cumulative impact of load forecast variability grows with time. Appendix F.1 lists the resulting simulated retail sales and summary statistics for the period 2015-2030.

Appendices F.5a and F.5b show the resulting simulated RPS target when accounting for the retail sales variability for the period 2015-2030 in the 33% and 40% RPS, respectively.

6.2.2 RPS Generation Variability

Based on analysis of historical hydro generation data from [redacted], wind generation data from [redacted], and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is essentially uncorrelated among technologies. Appendices F.3a and F.3b list the resulting simulated generation and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, Appendices F.4a and F.4b, combine the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, shows how these variables interact in the 33% and 40% RPS, respectively.

6.2.3 Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). [redacted]

[redacted] 28

These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information regarding curtailment.

6.2.4 Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] chance of success. This success rate

---

28 [redacted]

is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Projects that are re-contracted, in contrast, are modeled at a [redacted] success rate. Appendices F.2a and F.2b list PG&E's simulated failure rate and summary statistics for the period 2015-2030 in the 33% and 40% RPS, respectively.

6.2.5 Comparison of Model Assumptions

Table 6-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 7 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 6-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years	Distribution based on most recent (2015) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. Re-contracted projects are assumed to have a [redacted] success rate.
3) RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4)	None	33% RPS Target: [redacted] of RPS requirement

Curtailment[29]		40% RPS Scenario: [redacted] of RPS requirement through 2021, increasing to [redacted] in 2024 and beyond.

6.3 How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position and procurement need. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

6.4 How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives, (b) inputs, and (c) constraints of the model.

    a. <u>The objective</u> is to minimize procurement cost.

    b. <u>The inputs</u> are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes[30]) in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero

---

29 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance.

30 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can also re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive.

and no more than [redacted] GWh, which is in addition to volumes available for re-contracting.[31]

c. The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.

3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.

4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not currently consider speculating on price volatility through sales of PG&E's Bank in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2015 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not

---

31 PG&E limited modeling to a maximum addition of [redacted] GWh per year in order to avoid modeling outcomes that required "lumpy" procurement patterns. Large swings in annual procurement targets could lead to boom/bust development cycles and could expose PG&E's customers to additional price volatility risk.

approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.

6.5 Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the 33% and 40% RPS are shown in Row La of PG&E's Alternate RNS in Appendices C.2a and C.2b.

The stochastic model does not provide guidance on potential sales of excess banked procurement at this time. However, as PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for [redacted] above the [redacted] threshold.

The results of both the deterministic and stochastic models are discussed further in Section 7 and minimum margin of procurement is addressed in Section 8.

7 Quantitative Information

As discussed in Section 6, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix C. Appendices C.1a and C.1b presents the RNS in the form required by the *Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendices C.2a and C.2b are a modified version of Appendices C.1a and C.1b to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its bank size and PG&E's analysis of the minimum bank needed. However, in approving the 2015 RPS Plan, the Commission expressly rejected any specific bank size proposal and instead indicated that proposals regarding bank size should be considered in SB 350's implementation.

7.1 Deterministic Model Results

Results from the deterministic model under the 33% RPS target are shown as the physical net short in Row Ga of Appendices C.1a and C.2a, while the results from the deterministic model under the 40% RPS scenario are shown as the physical net short in Row Ga of Appendices C.1b and C.2b. Appendices C.1a and C.1b provide a physical net short calculation using PG&E's Bundled Retail Sales Forecast for years 2015-2019 and the LTPP sales forecast for 2020-2035, while Appendices C.2a and C.2b rely exclusively on PG&E's internal Bundled Retail Sales Forecast. Following the methodology described in Section 6.1, PG&E currently estimates a long-term volumetric success rate of approximately 99% for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendices C.2a and C.2b. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendices C.2a and C.2b depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

7.1.1 33% RPS Target Results

Under the current 33% RPS target, PG&E is well-positioned to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.1b, the deterministic model shows a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2a also shows a physical net short of approximately 500 GWh beginning in 2022.

7.1.2 40% RPS Scenario Results

Under a 40% RPS scenario, PG&E is forecasted to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.2b, PG&E has a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2b shows a physical net short of approximately 3,000 GWh beginning in 2022.

7.2 Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for both the current 33% RPS target and a 40% RPS scenario. All assumptions and caveats stated in the discussion of the 33% RPS target results apply to the 40% RPS scenario results, unless otherwise stated. However, note that the 40% RPS scenario results apply to this particular RPS scenario only, and PG&E's optimization strategy may differ under other scenarios that have a different RPS target or timeline. Because PG&E uses its stochastic model to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix C.2a for the current 33% RPS target and Appendix C.2b for the 40% RPS scenario. Appendices C.1a and C.1b provide an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendices C.2a and C.2b, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short

~~(“SANS”),~~, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E’s SONS.

7.2.1 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 33% RPS Target

To evaluate possible procurement strategies, PG&E selected a cumulative ([redacted]) non-compliance risk target of [redacted], which PG&E views as the maximum reasonable level of non-compliance risk. Figure 7-1 shows the model’s forecasted procurement need and resulting Bank usage under the current 33% RPS. Under this projection, a portion of the Bank is used to meet PG&E’s compliance need beginning in [redacted], the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2a provides the detailed results. Annual forecasted Bank usage is shown in Row Ia of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as [redacted]. This compliance period need represents PG&E’s SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by 2030. The [redacted] SONS is [redacted] than the physical net short in Row Ga for [redacted], as the SONS ~~XXXXXXXXXXXXXXXXXX~~XXXXXXXXXXXXXXXXXXX [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

7.2.2 Bank Size Forecasts and Results – 33% RPS Target

Figure 7-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2030. PG&E's total Bank size as of the end of compliance period is approximately 900 GWh, shown as existing Bank in Figure 7-2. The stochastic model's results currently project PG&E's Bank size to [redacted] GWh by [redacted] (as shown in Figure 7-2, as well as in Appendix C.2a, Row J). [redacted]

[redacted]

[redacted]

[redacted]

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement.

In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases.

7.2.3 Minimum Bank Size – 33% RPS Target

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 7-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]. This time period was selected as it best represents a "steady state" period when the Bank approaches a minimum level and moderate incremental procurement is required to maintain compliance. Note that given the uncertainty around the inputs in the stochastic model, without a Bank to accommodate such uncertainty, the amount of RPS generation is almost as likely to miss the RPS target as exceed it. One standard deviation over [redacted] is approximately [redacted] GWh, as indicated on Figure 7-3. That is, given this particular procurement scenario, about 68% of the simulations have a difference that is up to plus or minus approximately [redacted] GWh.

However, this does not suggest that a Bank of [redacted] GWh would be adequate to cover potential shortfalls over this [redacted]-year period. It would result in an unacceptable non-compliance risk over [redacted] of approximately [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level. Based on current model assumptions and inputs, Figure 7-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

[redacted]

[redacted]

[redacted]

As stated in Section 7.2.2, the stochastic model's results show PG&E's forecasted [redacted] PG&E's strategy is to procure steady, incremental volumes in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs and maintain minimum Bank levels. [redacted]

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 7-3 illustrates.

7.2.4 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 40% RPS Scenario

Figure 7-4 shows the model's forecasted procurement need and recommended Bank usage in the 40% RPS scenario. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2b provides the detailed results. Annual forecasted Bank usage can be seen in Row Ia of this Appendix. The first year of procurement need is currently forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by [redacted]. The [redacted] SONS is [redacted] than the physical net short shown in Row Ga for [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

7.2.5 Bank Size Forecasts and Results – 40% RPS Scenario

Figure 7-5 shows PG&E’s current and forecasted cumulative Bank from Compliance Period 1 through 2030 under a 40% RPS scenario. PG&E’s total Bank size as of the end of Compliance Period 1 is approximately 900, shown as existing Bank in

Figure 7-5. The stochastic model's results currently project PG&E's [redacted] (as shown in Figure 7-5, as well as in Appendix C.2b, Row J).

[redacted]

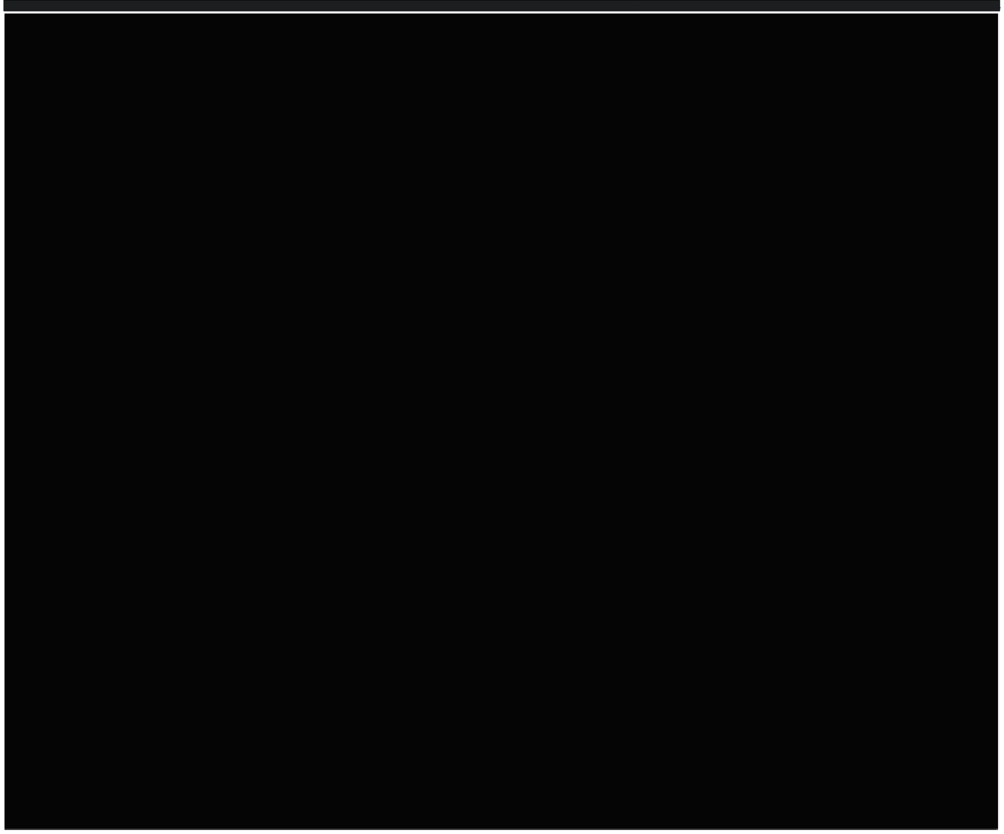
[redacted]

[redacted]

[redacted]

7.2.6 Minimum Bank Size – 40% RPS Scenario

Using a similar approach as described in Section 7.2.3, under a 40% by 2024 scenario, a minimum Bank size of at least [redacted] GWh is necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. The minimum Bank size in this scenario is greater than the Bank required for the 33% RPS target, as more volumes are required to meet the higher RPS, but also [redacted].



The stochastic model's procurement strategy results show PG&E's forecasted [redacted]. Based on current model assumptions and inputs, Figure 5-6 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted].

7.3 Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales of surplus procurement. Consistent with the Commission's adopted RNS methodology, PG&E's physical net short and cost projections do not include any projected sales of bankable contracted deliveries. However, PG&E will consider selling non-bankable surplus volumes in its portfolio and, in doing so, may identify and propose in the future opportunities to secure value for its customers through the sale of bankable surplus procurement. PG&E will update its physical RNS if it executes any such sale agreements and will include in its optimized RNS and SONS specific future plans to sell RPS procurement.

8 Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 33% RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

8.1 Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[32] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[33]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[34] However, as discussed in Sections 6 and 7, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of

---

32 Cal. Pub. Util. Code § 399.13(a)(4)(D).

33 *Id.*, § 399.15(b)(5)(B)(iii).

34 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums. However, its revised success rate assumption (from 87% to 99%) also reflects several recent contract terminations from PG&E's portfolio due to and an update to the "Closely Watched" category described in Section 6.

procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

8.2 Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin of procurement.[35] As discussed further in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects [redacted]. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 33% RPS target, and will thus reduce long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 6 and 7.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

---

35 *Id.*,§ 399.13(a)(4)(D).

9 Bid Selection Protocol

As described in Sections 3 and 7, PG&E is well positioned to meet its RPS targets, under both a 33% RPS target and a 40% RPS scenario, until at least [redacted]. As a result, PG&E ~~proposes that it~~will not issue a 2015 RPS solicitation. PG&E will continue to procure RPS-eligible resources in 2016 through other Commission-mandated programs, such as the ReMAT and RAM Programs. To reflect that PG&E will not issue a 2015 RPS Solicitation, language has been added throughout the final 2015 RPS Plan to confirm that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2015 RPS Plan, except for RPS amounts that are separately mandated.

In D.15-12-025, the Commission required in Ordering Paragraph 7 that PG&E "include a description of how their process ensures that there is no double counting between the Integration Cost adder and the Net Market Value components in the Least-Cost Best-Fit methodology of [its] RPS plan[]. . .." If PG&E were to procure RPS resources, there would be no double counting between the integration cost adder and the Net Market Value ("NMV") components in the Least-Cost Best-Fit ("LCBF") methodology that would be used by PG&E. NMV measures the cost of the renewable resource in terms of direct impacts on ratepayers—PPA payments to the supplier plus transmission costs and integration costs, less the energy and capacity value of the resource. It is associated with the marginal value of the energy and capacity produced directly by the resource—it is the market cost that PG&E no longer incurs because it is procuring energy and capacity from the resource instead. The integration cost represents the system costs that are incurred for *other* resources that are needed to support the additional renewable resource. The variable cost represents the incremental cost of running existing flexible units in the short term, and the fixed cost represents the incremental cost of additional flexible RA capacity to support the additional renewable resource.

9.1 Proposed ~~TOD~~Time of Delivery Factors

PG&E sets its Time of Delivery ("TOD") factors based on expected hourly prices. Given the high penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be significant periods of time during the mid-day when net loads are low, resulting in prices that will be low or negative, especially in the spring. This expectation is consistent with forecasts of net load that have been publicized by the CAISO.[36] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. Thus, PG&E would simplify its PPAs and include only a single set of TOD factors to be applied to both energy-only and fully deliverable resources.

PG&E is ~~proposing to update~~updating its TOD factors and TOD periods as follows:

~~Recommendation (~~New TODs~~)~~

- Move peak period from HE16-HE21 to HE17-HE22
- Move mid-day period from HE07-HE15 to HE10-HE16
- Move night period from HE22-HE06 to HE23-HE09
- Move March back to the "Spring" period
- Result: Summer=Jul.-Sep., Winter=Oct.-Feb., Spring=Mar.-Jun.; and Peak=HE17-HE22, Mid-day=HE10-HE16, Night=HE23-HE09

TABLE 9-1
~~[PROPOSED~~ RPS TIME OF DELIVERY FACTORS~~]~~

	Peak	Mid-Day	Night
Summer	1.479	0.604	1.087
Winter	1.399	0.718	1.122
Spring	1.270	0.280	1.040

---

36 *See*, *e.g.*, *CAISO Transmission Plan 2014-2015*, pp. 162-163 (approved March 27, 2015) (available at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).

10 Consideration of Price Adjustment Mechanisms

The ACR requires each IOU to “describe how price adjustments (e.g., index to key components, index to Consumer Price Index~~,~~ (“CPI”), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date.”[37]

PG&E will consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.[38] In order to maximize the RPS Program’s benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission’s expressed desire to standardize and simplify RPS solicitation processes.[39]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may

---

37 ACR, p. 15.

38 *See* Cal. Pub. Util. Code § 399.11(b)(5).

39 *See* D.11-04-030, pp. 33-34.

not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the ~~Consumer Price Index ("CPI").~~CPI. The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

11 Economic Curtailment

In D.14-11-042, the Commission approved curtailment terms and conditions for PG&E's pro forma RPS PPA.[40] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the Procurement Review Group ("PRG").[41] In May 2015, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally, and PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in 2015 has generally increased in the Real-Time Markets, even during the low hydro conditions of 2015. During January through May 2015, negative price intervals in the CAISO Five Minute Market for the North of Path 15 Hub occurred more than 1,800 times (4.2% of 5 minute intervals) compared to 1,100 times (2.5%) during the same period in 2014. Similarly, the ZP26 Hub prices for this period in 2015 were negative over 4,100 times (9.5%), a substantial increase over the 2014 results of 1,400 times (3.3%). Increased negative price periods have led to increased curtailments of renewable resources that are economically bid. The specific

---

40 D.14-11-042, pp. 43-44.

41 *Id.*, pp. 42-43.

occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted] ~~XXXXXXXX~~XXXXXXX..

[redacted] [42] [redacted] ~~XXXXXXXXXXXXXXX~~XXXXXXXXXXXXXX PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. This also includes the incremental costs of compliance instruments required to comply with the 33% RPS target. PG&E provided more detail concerning its RPS bidding strategy in its proposed 2014 ~~Bundled Procurement Plan ("BPP")~~ BPP which was filed with the Commission in October 2014 and is currently pending at the Commission.[43]

[redacted]

---

42 [redacted]

43 *See* PG&E, *Proposed 2014 Bundled Procurement Plan*, R.13-12-010, Appendix K (Bidding and Scheduling Protocol) (October 3, 2014).

[redacted][44][redacted][45][redacted][46] While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods and also potentially enhancing CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. Under the 33% RPS target, PG&E assumes curtailment [redacted][47] under a 40% RPS scenario, PG&E expects curtailment to increase in line with recent CAISO estimates [redacted].[48] These modeling assumptions will not

---

44 [redacted]

45 [redacted]

46 [redacted]

47 [redacted]

48 [redacted]

necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

12 Expiring Contracts

The ACR requires PG&E to provide information on contracts expected to expire in the next 10 years.[49] Appendix E lists the projects under contract to PG&E that are expected to expire in the next 10 years. The table includes the following data:

1. PG&E Log Number
2. Project Name
3. Facility Name
4. Contract Expiration Year
5. Contract Capacity (MW)
6. Expected Annual Generation (GWh)
7. Contract Type
8. Resource Type
9. City
10. State
11. Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA

As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects

[49] ACR, p. 16.

that proposed material amendments (i.e., those needed to avoid project failure) or extensions to existing contracts will be evaluated against current offers.

13 Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix D provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix D outlines the methodology for calculating the costs and generation.

13.1 RPS Cost Impacts

Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-2014) and forecast (2015-2030). From 2003 to 2014, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than [redacted] in procurement costs for RPS-eligible resources in 2014.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS-eligible procurement and generation. While this formula does not provide an estimate of the renewable "above-market premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix D illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 3.5¢/kWh in 2016, meaning the average rate impact from RPS-eligible procurement has increased more than five-fold in approximately 12 years. This growth rate is projected to continue increasing through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

13.2 Procurement Expenditure Limit

Section 399.15(f) provides that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding "a de minimis increase in rates." The methodology for the PEL, the Commission's cost containment mechanism, is still under development. As discussed in Section 2.2, PG&E looks forward to the Commission finalizing the PEL methodology and implementing it, to ensure that customers are adequately protected and promote regulatory certainty and support procurement planning.

13.3 Cost Impacts Due to Mandated Programs

As PG&E makes progress toward achieving the RPS goal of 33%, the cost impacts of mandated procurement programs that focus on particular technologies or project size increase over time, and procurement from those programs increasingly comprises a larger share of PG&E's incremental procurement goals. In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[50] Studies have also

---

50 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et. al, "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

shown that renewable electricity mandates increase prices and costs,[51] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants and second, by creating a less robust market for participants to compete.[52] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

14 Imperial Valley

For the IOUs' 2014 RPS solicitations, the Commission did not specifically require any remedial measures to bolster procurement from Imperial Valley projects but required continued monitoring of IOUs' renewable procurement activities in the Imperial Valley area.[53] Even without remedial measures in PG&E's 2014 RPS Solicitation, the Independent Evaluator monitoring that solicitation found that:

---

51 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call" (available at http://www.instituteforenergyresearch.org/pdf/statereport.pdf); Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

52 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

53 D.14-11-042, pp. 15-16.

> Overall, the response of developers to propose Imperial Valley projects was robust and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to developers active in the Imperial Valley or that there was any structural impediment in the RFO process that hindered the selection of competitively priced Offers for projects in the Imperial Valley.[54]

Given the robustness of the response from Imperial Valley projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, and given the fact that PG&E is not planning on conducting a 2015 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the Imperial Valley as a part of the RPS Plan.

The ACR also directs the IOUs to report on any CPUC-approved RPS PPA for projects in the Imperial Valley that are under development, and any RPS projects in the Imperial Valley that have recently achieved commercial operation.[55] PG&E has one PPA under contract in the Imperial Valley. That project is in development. Commercial operation is expected in 2016, with deliveries under the PPA beginning in 2020.

15 Important Changes to Plans Noted

This section describes the most significant changes between PG&E's 2014 RPS Plan and its 2015 RPS Plan. A complete redline of the draft 2015 RPS Plan against PG&E's 2014 RPS Plan ~~is~~was included as Appendix A~~.~~ of the August 4, 2015 draft RPS Plan. This section identifies and summarizes the key changes and differences between the 2014 RPS Plan and the proposed 2015 RPS Plan. Specifically, the table below provides a list of key differences between the two RPS Plans:

---

54 PG&E, *Advice Letter 4632-E*, p. 40, Section 2 (IE Report) (May 7, 2015).

55 ACR, p. 19.

Reference	Area of Change	Summary of Change	Justification
Section 1	Section format and structure	Remove "Executive Summary" from Introduction.	Ease of document flow.
Entire RPS Plan	Consideration of a Higher RPS Requirement	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Section 2.1	Commission Implementation of SB 2 (1x)	Include discussion of D.14-12-023, setting RPS compliance and enforcement rules under SB 2 (1X).	ACR at p. 4.
Section 3.2.2	Impact of Green Tariff Shared Renewable Program	Include discussion of impact of Green Tariff Shared Renewable Program on RPS position.	D.14-11-042; D.15-01-051.
Section 3.4	Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations	Include discussion of integration cost adder as part of LCBF bid evaluation methodology.	ACR at p.15.
Section 3.5	RPS Portfolio Diversity	Include discussion of efforts to increase portfolio diversity.	ACR at p.10.
Section 5.4	Curtailment of RPS Generating Resources	Include discussion of economic curtailment as a potential compliance delay.	ACR at p.16.

Reference	Area of Change	Summary of Change	Justification
Section 11	Economic Curtailment	Include discussion of economic curtailment.	ACR at p.16.
Appendix C.1b	Renewable Net Short Calculations – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix C.2b	Alternate Renewable Net Short Calculations – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.2b	Project Failure Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.3b	RPS Generation Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.4b	RPS Deliveries Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.
Appendix F.5b	RPS Target Variability – 40% RPS Scenario	Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.	ACR at pp.5-6.

16 Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

16.1 Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2015 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[56] PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, PG&E's Safety Commitment, Personal Safety Commitment and Keys to Life.[57] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental

---

56 *See* PG&E, "Employee Code of Conduct" (August 2013) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 3 (available at http://www.pgecorp.com/aboutus/ethics_compliance/con_con_ven/).

57 *See* PG&E, "Employee Code of Conduct" *supra* (describing the Safety Principles, Safety Commitment, Personal Safety Commitment and Keys to Life).

authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its General Rate Case ("GRC"),[58] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the ~~California Public Utilities Commission's~~CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance.

---

58 *See* PG&E, *Prepared Testimony, 2014 GRC, Application 12-11-009*, Exhibit (PG&E-6), Energy Supply, pp. 1-11, 2-17, 2-44, 2-66, 4-13 (available at http://www.pge.com/regulation/).

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident ("MVI") Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800 phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and re certification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E is developing and implementing a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

PG&E will never be satisfied in its safety performance until there is never an injury to any of its employees, contractors, or members of the public. Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement change that can improve safety performance.

16.2 Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. While this authority has not changed, PG&E intends to add additional contract provisions to its contract forms to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

Specifically, the safety language that PG&E is developing builds upon the former standard of Good Utility Practices to a new standard of Prudent Utility Practices, which includes greater detail on the types of activities covered by this standard, including but not limited to safeguards, equipment, personnel training, and control systems.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information. Additionally, the new contract provisions would require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. If the generator has repeated safety violations or challenges, the generator could be at greater risk of failing to meet a key project development milestone or failing to meet a material obligation set forth in the PPA.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

17 Energy Storage

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014. In D.14-10-045, the CPUC approved PG&E's application with modifications. PG&E ~~will file~~filed final storage RFO results for CPUC approval ~~by~~on December 1, 2015. In addition, PG&E is participating in a new proceeding, R.15-03-011, which the Commission opened in March 2015 to consider policy and implementation refinements to the energy storage procurement framework and program design.

PG&E considers eligible energy storage systems to help meet its Energy Storage Program targets through its RPS procurement process, Energy Storage RFO, as well as other CPUC programs and channels such as the Self~~-~~-Generation Incentive Program~~ (SGIP).~~. PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[59]

---

59 *See* PG&E, *Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Resources (2014-2015 Biennial Cycle)*, (available at: http://www.cpuc.ca.gov/NR/rdonlyres/D9CACD21-AB1C-411A-8B79-84FB28E88C58/0/PGE_StorageApplication.pdf).